Shale Energy Technology Assessment: Current and Emerging Water Practices

Updated July 14, 2014

Congressional Research Service
https://crsreports.congress.gov
R43635

Summary

Shale oil and gas (collectively referred to as shale energy), long considered "unconventional" hydrocarbon resources, are now being developed rapidly. Economic extraction of shale energy resources typically relies on the use of hydraulic fracturing. This technique often requires significant amounts of freshwater, and fracturing flowback and related wastewaters must be recycled or disposed of after a well is completed. While shale energy presents a significant energy resource, its development has the potential to pose risks to water availability and water quality.

This report provides a technological assessment of existing and emerging water procurement and management practices in shale energy-producing regions of the United States. The intersection of evolving technology, growing environmental concerns, demand for new sources of hydrocarbon energy, and the potential national interests in developing shale oil and gas resources provides the context for this study. Congressional attention has been focused on two key aspects of the issue: shale energy as a growing U.S. energy source, and environmental concerns associated with the development of these resources.

Water for shale energy projects is used most intensely in the fracturing portion of a well's life cycle. Under current practices, fracturing typically is a water-dependent activity, often requiring between a few million and 10 million gallons of water per fractured horizontal well. This water demand often is concentrated geographically and temporally during the development of a particular shale formation. Production activities and management and treatment of the wastewater produced during shale energy production (including flowback from fracturing and water produced from source formations) have raised concerns over the potential contamination of groundwater and surface water and induced seismicity associated with wastewater injection wells.

Water resource issues may pose constraints on the future development of domestic shale oil and gas. Potential negative effects from shale energy extraction—particularly effects associated with hydraulic fracturing and wastewater management—have prompted state and regional regulatory actions to protect water supplies. Future congressional and executive branch actions may influence development of shale oil and shale gas on federal lands and elsewhere through additional regulatory oversight or other policy actions. At the same time, advances in shale energy extraction and wastewater management techniques may reduce some development impacts.

The pace of technological change in water sourcing and water management in the shale energy sector is rapid, but uneven. Trends in water management have generally been influenced by local disposal costs, regulations, and geologic conditions rather than by water scarcity alone. Emerging technologies and practices in water resources management can be divided into those that seek to reduce the amount of consumptive freshwater utilization in the drilling and completion process, and those that seek to lower the costs and/or minimize the potential for negative environmental impacts associated with wastewater management.

Water management issues are relevant to the entire life cycle of shale energy development, because fluids will continue to be produced even after a well is drilled, fractured, and producing oil and/or natural gas. Research that views the shale energy production process in a life-cycle and materials-flow context may facilitate the identification of technologies and processes that can mitigate potential impacts along different stages of shale energy development.

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Report Authorship

This technology assessment was undertaken by Pennsylvania State University, with contributions from Michael Arthur, Seth Blumsack, Thomas Murphy, David Yoxtheimer, and Ross Pifer. Their work was performed under contract to CRS, and was part of a multiyear CRS project to examine various aspects of U.S. energy policy. John L. Moore, Assistant Director of the Resources, Science, and Industry Division, served as CRS project coordinator. Mary Tiemann, Specialist in Environmental Policy, Peter Folger, Specialist in Energy and Natural Resources Policy, and Nicole Carter, Specialist in Natural Resources Policy, served as CRS reviewers and editors of this report. This assessment is one of two reports produced by the authors; see also CRS Report R43636, *U.S. Shale Gas Development: Production, Infrastructure, and Market Issues*.

The material in this report is current as of 2013. The report will not be updated.

Acknowledgement

This report was funded, in part, by a grant from the Joyce Foundation.

Introduction

This report provides an assessment of current and emerging water procurement and management technologies and practices related to shale energy development in the United States. Water resource management issues associated with shale energy development are of concern to policy makers because shale energy represents an opportunity as well as a challenge. Shale oil and natural gas present significant new energy resources, but their development also may pose risks to water quality and other water uses.[1] The intersection of evolving technology, environmental protection, hydrocarbon energy demand, and national and geopolitical energy and trade interests provide the context for this study.

Shale gas and shale oil[2] (collectively referred to as *shale energy*), which were long considered "unconventional" hydrocarbon resources, are now experiencing significant development in the United States. Shale oil and gas represent substantial fossil fuel resources for heating, electricity generation, transportation fuel, and industrial use. Economical extraction relies on directional drilling and hydraulic fracturing ("fracking"). This well-completion technique involves the injection of large volumes of water, along with water-conditioning chemicals and sand or other proppants, to pressurize and fracture shale formations to increase reservoir permeability.[3] The proppant holds the fracture open, allowing gas and oil to move to the well bore. A portion of the injected water, commonly referred to as "flowback," and naturally occurring water from the shale formation itself, referred to as "produced water," then return to the surface with the oil and/or gas.

For the purposes of this report, the combination of flowback and produced water, unless distinguished separately, will be referred to as "produced fluids." The term "wastewater" is also

[1] Shale oil and gas development also poses challenges to air quality, land management, and other environmental issues, which are not discussed in this report.

[2] In this report, "shale oil" refers to the naturally occurring petroleum extracted from tight shale formations (sometimes called "oil-bearing shales") utilizing hydraulic fracturing methods. Shale oil, as used in this report, is distinct from "oil shale," which refers to unconventional oils extracted from rock formations through pyrolysis.

[3] For the purposes of this report, hydraulic fracturing refers to the process of injecting fluid and a proppant, such as sand, at high pressure into a geologic formation for the purpose of fracturing the rock to allow natural gas or oil to flow

used, and includes produced fluids as described above, but may also contain other fluids produced during the drilling and development of shale energy wells.

The current level of freshwater used for fracturing and the management (reuse or disposal) of the produced fluids from the extraction are seen by some stakeholders as limiting factors in shale energy development. Shale energy development also poses the potential for contamination of surface water and groundwater resources through multiple pathways:

- accidental surface spills of chemicals used in hydraulic fracturing;
- accidental spill of wastewaters from well operations;
- improper disposal of wastewaters;
- well fluids leaking from valves and casings, including uncontrolled blowouts; and
- leakage and migration of gas and fluids at wells (e.g., improper well construction).[4]

While some of these concerns are specific to shale development, others are common to most energy development activities. However, the large volumes of fluids, chemicals, and injection pressures associated with high-volume hydraulic fracturing have posed new well development and wastewater management challenges for the industry and regulators.

This report discusses the water inputs to shale energy development, wastewater management related to shale energy development (including some related topics such as induced seismicity), and emerging water technologies for both the production of shale energy and the disposal of wastewaters. The report is intended to be a snapshot of current knowledge about water issues and technology development related to shale energy development, and will not be updated. This report is limited to well development-related issues; it does not discuss water-related risks associated with transport of shale-derived energy resources.

Primer on Shale Energy Resources Development

The extraction of shale energy has the potential to affect U.S. energy security by reducing quantities of crude oil and refined petroleum products purchased in global markets. Additionally, shale gas contributes to the United States' effective independence regarding natural gas. When used as a fuel, natural gas, composed primarily of methane, is viewed as having lower emissions of many air pollutants relative to coal or oil as a fuel source, and is seen by some as a "bridge fuel" to a less greenhouse-gas-intensive energy future.[5] While these are some of the drivers

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from the formation into the production well and be recovered at the surface. (Proppants are particles, such as sand or ceramic beads, that are mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.)

[4] Methane is the main component of natural gas. Methane leakage and migration pathways have received considerable attention, in part because of the difficulty in tracking, monitoring, and attributing specific methane incidents to shale energy activities. Incidents of "stray gas" (attributed to methane migration in the subsurface) in Pennsylvania, for example, have generally not been associated with drilling shale gas wells per se, but with preexisting methane in subsurface waters or from improperly abandoned and unknown older wells. However, some studies have linked increased levels of natural gas in groundwater with proximity to natural gas wells. See Robert B. Jackson et al., "Increased Stray Gas Abundance in a Subset of Drinking Water Wells Near Marcellus Shale Gas Extraction," *Proceedings of the National Academy of Sciences*, June 24, 2013, http://www.pnas.org/content/early/2013/06/19/1221635110?tab=author-info.

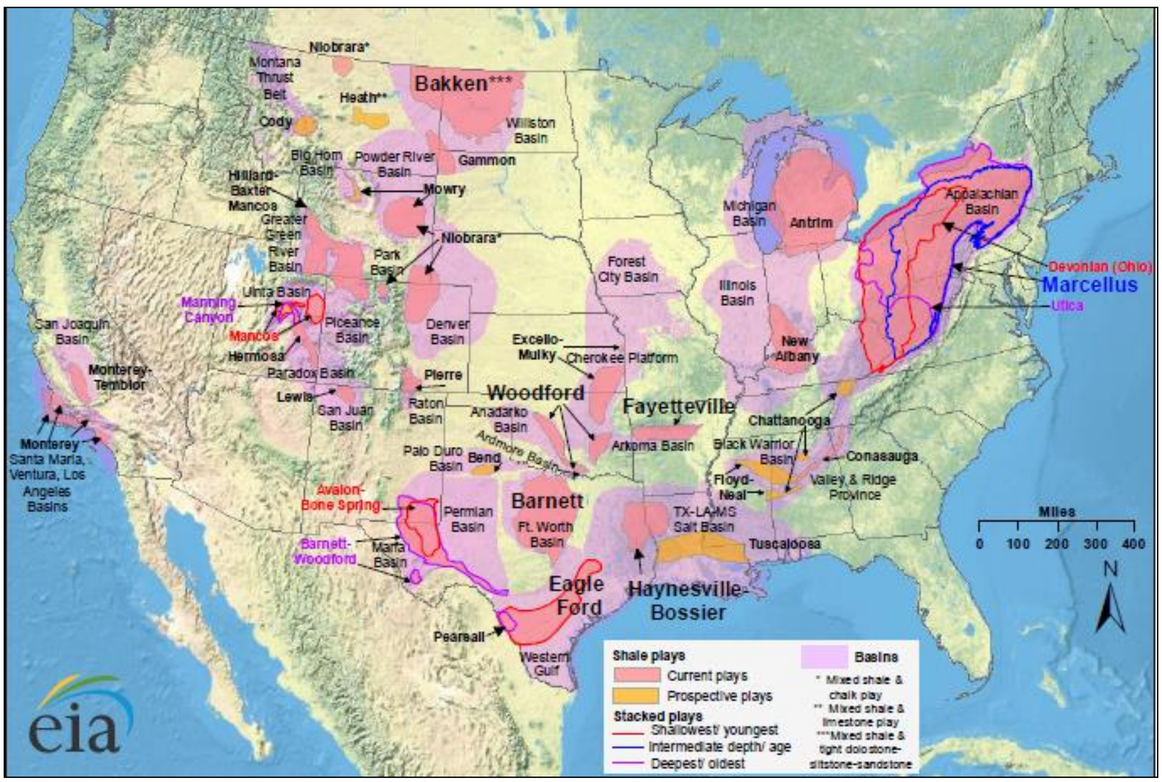
[5] However, methane is a significantly more potent greenhouse gas than carbon dioxide (although less persistent in the atmosphere); consequently, the advantage of natural gas over other fossil fuels would depend partly on the amount of

behind interest in shale energy, how shale energy is developed bears directly upon its impact on water resources. This section provides a brief introduction to how shale energy is developed in the United States.

Location of Shale Resources

Shale energy deposits vary in size, depth, and quality across the United States. Some deposits occur primarily in one state—for example, the Barnett Shale in Texas. Others underlie multiple states, such as the Marcellus Shale in New York, Pennsylvania, and West Virginia. The Marcellus Shale is currently considered the largest potential resource of shale gas, and is close to large energy-demand centers in the Northeast. The Utica Shale in Ohio and portions of the midwestern United States represents another sizable natural gas resource that is just starting to be developed. **Figure 1** illustrates key shale energy formations in the lower 48 states.[6]

Figure 1. U.S. Shale Gas and Shale Oil Plays in the Contiguous United States



Source: U.S. Energy Information Administration, 2011.

fugitive methane emissions from the natural gas sector. CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio, provides an introduction to emissions associated with natural gas systems. Several studies assess and compare life-cycle emissions of both conventional air pollutants and greenhouse gases (GHGs) from production and use of various fossil fuels. A summary analysis of greenhouse gas analyses can be found in Weber, Christopher, and Christopher Clavin, 2012, "Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications," *Environmental Science and Technology* 46, pp. 5688-5695.

[6] In addition to the Energy Information Administration (EIA) map presented in **Figure 1**, the U.S. Geological Survey produces a report and map on shale gas assessments; see Laura R.H. Biewick, compiler, *Map of Assessed Shale Gas in the United States, 2012*, U.S. Geological Survey, Digital Data Series 69-Z, 2013, http://pubs.usgs.gov/dds/dds-069/dds-069-z/.

> **Note:** The term "play" does not have a specific definition, but generally refers to a set of known or postulated oil and/or gas accumulations sharing similar geologic and geographic properties, and containing a quantity of oil or gas that may be developed economically.

Some deposits are primarily natural gas-bearing formations, while others contain significant oil resources. For example, well development in the Bakken Shale in North Dakota is often performed in pursuit of oil resources, while wells in the Eagle Ford Shale of Texas produce gas and oil in varying ratios depending largely on a well's location in the shale formation. Although interest in recovery of shale oil from the Monterey Shale of California continues, uncertainties remain about the near-term prospects for this development. Shale energy resources can typically be extracted economically only by using the hydraulic fracturing technique. This technique requires large volumes of water to pressurize the formations to increase reservoir permeability. Water is used in conjunction with a proppant for this purpose; proppant composition varies, but generally consists of sand or ceramic beads designed to be emplaced into fractures to maintain sufficient fracture width. The injected water opens up fractures and then delivers the proppant. Together, the injected mixture is known collectively as "fracking fluids."

To fracture a well, water is pumped from its storage site and mixed with the desired proportion of proppants and water-conditioning chemical additives.[7] Once blended, the mixture is injected into the well at pressures typically ranging from 8,000 pounds per square inch (PSI) to 10,000 PSI to achieve enhanced formation permeability. The volume of water, sand, and additives used for fracturing a horizontal well is typically about 4 million to 5 million gallons, but can vary from 2 million to 10 million or more gallons depending on the fracturing design and well type (e.g., fracturing of a vertical well often uses less water than fracturing a horizontal well).

In addition to commodity prices and market fundamentals of supply and demand, there are three key, interrelated sources of uncertainty affecting the pace of shale energy development: market structures, regulation, and public perception. Regarding market structure, shale gas and shale oil face some similar and some different uncertainties. Despite commonalities in current shale energy development technologies for shale oil and shale gas, the logistics of transporting oil versus natural gas to market are very different, as are pricing structures for the two commodities. Thus not all sources of uncertainty are likely to affect all segments of the shale energy industry uniformly.[8]

The second source of uncertainty is regulatory in nature. The policy attitude toward shale gas is evolving at multiple levels including local, state, and federal. Policy is evolving in the areas of air and water quality, water utilization, and land use (zoning). Substantial variations in regulatory approaches exist among states with active shale energy industries. Many such states, for example, permit some form of *forced pooling*,[9] which allows for horizontal drilling underneath a landowner's property (with compensation) even if the landowner has not explicitly signed a lease. Among active shale energy states, Pennsylvania and West Virginia do not have forced pooling in deep geologic formations (but do in shallower geologic formations from which oil and gas have been extracted for decades).[10] As of the end of 2013, Pennsylvania was in the process of developing policy that would permit forced pooling in the Marcellus Formation.

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[7] The website FracFocus includes a list and description of the typical chemical additives used for hydraulic fracturing: http://fracfocus.org/chemical-use/what-chemicals-are-used.

[8] For a discussion of natural gas markets, infrastructure, and related issues, see CRS Report R43636, *U.S. Shale Gas Development: Production, Infrastructure, and Market Issues*.

[9] Forced pooling is also called "compulsory unitization." Such policies are intended to develop resources most efficiently, based on the geology of the resource deposit.

[10] Resources for the Future (RFF), 2012, "A Review of Shale Gas Regulations by State," available at http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx, last viewed December 22, 2012.

Regulatory uncertainty is challenging for shale energy production and transportation, particularly natural gas, due to the sunk nature of capital investments (power plants cannot quickly be repurposed, for example). Virtually all energy projects require large investments in capital that are sunk, but natural gas delivery is especially dependent on sunk capital, particularly pipelines and, where appropriate, liquefied natural gas (LNG) terminals. Since the mode of transportation for natural gas is not fungible (i.e., transportation cannot easily be shifted from one mode to another, as is the case with oil and coal), stable long-term supply contracts are generally required to encourage investment in gas transmission infrastructure in emerging gas shale plays (and in some shale oil plays where substantial flaring of natural gas occurs, such as the Bakken Formation in North Dakota), but such contracts are difficult to establish when future regulatory costs are unknown.

The third source of uncertainty is caused by substantial gaps between risks as understood and communicated by scientists; risks as communicated in media reports; and risks perceived by the general public. These gaps emphasize the importance of science-driven policymaking, and seem especially prominent in the case of risks to environmental resources, particularly drinking water quality. There is no systematic scientific consensus that hydraulic fracturing of deep shale formations, if done properly, poses threats to local drinking water supplies. Nevertheless, public perception in many areas is otherwise. Moreover, regulators have determined in various cases that shale energy well development and operations (separate from hydraulic fracturing) have impacted water quality.[11] Homes near drilling sites in southwestern Pennsylvania that rely on piped water systems have, on average, increased in value, while those that use on-site wells have, on average, declined in value. Similar evidence regarding public perceptions surrounding water quality issues has been gathered in the United Kingdom.[12] Several studies in 2011 and 2012 demonstrating some hydrologic connectivity between groundwater supplies and fracture zones in the Marcellus Formation[13] have been variously interpreted as suggesting an explicit link between drilling activities,[14] and suggesting exactly the opposite.[15] A 2013 study suggested a geospatial connection with drilling activities that may warrant further scientific and regulatory investigation.[16] The U.S. Environmental Protection Agency (EPA) is currently studying this issue, pursuant to a congressional request, but to date has not released any findings.[17] Gaps in scientific understanding

[11] See, for example, New York State Department of Environmental Conservation, *Fact Sheet: What We Learned from Pennsylvania*, NYS DEC NEWS, http://www.dec.ny.gov/energy/75410.html. Beyond water quality issues, emissions of air pollutants and land-use changes also have generated significant concern for communities and landowners.

[12] Economic and Social Research Council (United Kingdom), 2012, "Fracking and Public Dialogue," available at http://www.esrc.ac.uk/impacts-and-findings/features-casestudies/features/20493/carousel-fracking-and-public-dialogue.aspx, last viewed December 22, 2012.

[13] Osborn, Stephen, Avner Vengosh, Nathaniel Warner, and Robert Jackson, 2011, "Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Sciences* vol. 108, no.20, http://www.pnas.org/content/108/20/8172; Nathaniel R. Warner et al., "Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvania," *Proceedings of the Natural Academy of Sciences*, vol. 109, no. 30, July 24, 2012, available at http://www.pnas.org/content/109/30/11961.

[14] For example, Mark Drajem, "Pennsylvania Fracking Can Put Water at Risk, Duke Study Finds," *Bloomberg Businessweek*, July 10, 2012, http://www.businessweek.com/news/2012-07-09/pennsylvania-fracking-can-put-water-sources-at-risk-study-finds.

[15] For example, Rachel Nuwer, "Fracking Did Not Sully Aquifers, Limited Study Finds," *New York Times*, July 9, 2012, http://green.blogs.nytimes.com/2012/07/09/fracking-did-not-sully-aquifers-limited-study-finds/.

[16] Robert B. Jackson et al., "Increased Stray Gas Abundance in a Subset of Drinking Water Wells Near Marcellus Shale Gas Extraction," *Proceedings of the National Academy of Sciences*, June 24, 2013, http://www.pnas.org/content/early/2013/06/19/1221635110?tab=author-info.

[17] Information on the EPA study is available at http://www2.epa.gov/hfstudy. EPA plans to issue a final report of results by the end of 2016.

on the potential impacts of shale energy development using high-volume hydraulic fracturing can heighten public concern and lead to increased regulatory scrutiny and uncertainty—note, for example, moratoria in Maryland, New York, and North Carolina.

Water Inputs into Shale Development

Hydraulic fracturing fluid must exhibit the proper viscosity and low friction pressure when pumped and used for well development. The fluid chemistry may be water-based, oil-based, or acid-based, depending on the properties of the formation. Water-based fluids, sometimes referred to as slickwater, are the most widely used, especially in shale formations because of their low cost, high performance, and ease of handling.

Water used in hydraulic fracturing may be piped or trucked from the source to the well-drilling area, depending on distance, rights-of-way, access, and topography. Water storage will typically occur on or near the well pad in either lined or earthen impoundments (typically built to codes determined at the state and local level), steel tanks, or temporary above-ground modular storage impoundments. The water is pumped from storage through a system of pipes, chemical blenders, pump trucks, valves, and pressure control devices (i.e., blowout preventers), and is then mixed with the desired proportion of proppants and chemical additives.

Fracturing initially requires significant water inputs, but while a well is producing there are few freshwater requirements unless refracturing is performed. Refracturing might be used to stimulate a well as production declines, possibly after a number of years. There are alternatives to water use for such procedures, but it is not known presently whether most shale energy wells will require refracturing or whether it will be economical to do so. Second, industry practices for water utilization, transportation, and treatment (or disposal) are evolving rapidly.

The following water sourcing topics for shale energy development are discussed below:

- water sources;
- costs associated with water inputs;
- water transport and storage; and
- access to water sources.

Water Sources: Availability of Groundwater and Surface Water

Regional differences in water availability may affect shale energy development over time. The most obvious constraints are likely to arise in arid to semiarid regions (but are not exclusive to arid and semiarid regions) that are already marginally to severely water-limited, and may become more so in the future.

The typical sources of water for well development have been surface or groundwater. Using surface water may require water transport to the well site via truck or pipeline, which may increase water-related costs and environmental and community impacts. Generally, surface water is a reliable water source in temperate regions, although it may become more difficult to access during drought periods or in isolated portions of a watershed. That is, although water may be regionally abundant in some regions, significant withdrawals can impact small streams in low flow periods. Groundwater can often be sourced at or near the drilling location, thereby reducing the costs and impacts associated with its transport for use in shale energy development. Water quality also must be considered for compatibility with hydraulic fracturing.

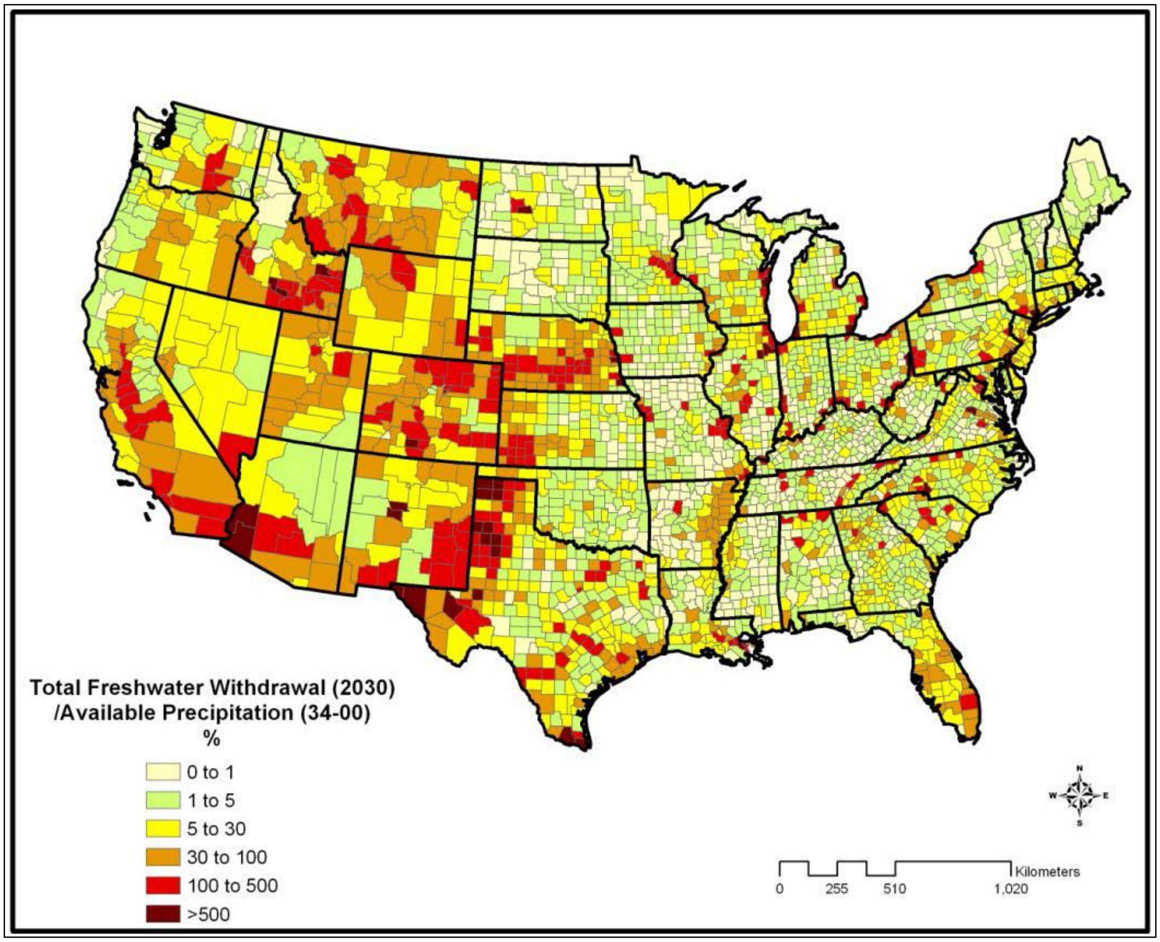
Shale energy projects in temperate regions, such as the Marcellus Shale and Utica Shale of the Appalachian Basin and the Haynesville Shale of East Texas and Western Louisiana, have used a combination of water purchased from municipal systems, industrial wastewater, and surface waters. In the Marcellus Shale in 2012, direct withdrawal from surface water represented 73% of shale energy water use; 27% of the water used came from municipal water systems.[18] In contrast, in the Eagle Ford Shale, aquifers have been the source for 90% of the water used in hydraulic fracturing; the other 10% is from surface supplies.[19] The following three figures illustrate where surface water and groundwater may be constrained given current levels of water use. **Figure 2** shows that the levels of use of existing surface water supplies (using precipitation as a simple measure of surface water availability) are already intensive in some locations. **Figure 3** shows that groundwater use in some locations exceeds aquifer recharge rates. For example, **Figure 3** shows that portions of Texas experiencing shale energy development like the Eagle Ford Shale (south Texas) and the Permian Shale (west Texas) had overdraft of aquifers at the onset of much of the shale energy development in 2005. **Figure 4** illustrates the variation in cumulative groundwater depletion over the course of more than a century for 40 U.S. aquifers.

[18] Jim Richenderfer, "Water Acquisition for Unconventional Natural Gas Development within the Susquehanna River Basin," Summary of the Technical Workshop on Water Acquisition Modeling: Assessing Impacts through Modeling and Other Means, June 4, 2013, pp. A-16, http://www2.epa.gov/sites/production/files/2013-09/documents/technical-workshop-water-acquisition-modeling.pdf. Based on analysis of SRBC permitting information, approximately 200 surface water intakes allowing in excess of 100 million gallons per day exist. Based on SRBC records, five basin groundwater wells are permitted for shale development. The limited use of groundwater in the Marcellus region is due in part to availability of surface waters and a lack of prolific aquifers co-located with shale resources.

[19] The Barnett play, however, located in central Texas, uses only 20% groundwater (Nicot, J.P., Reedy, R.C., Costley, R.A., and Huang, Y., 2012, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report*, prepared for Texas Oil & Gas Association, Austin, Texas).

Figure 2. Surface Water Use in the U.S. Contiguous United States

(withdrawal as percent of available precipitation)

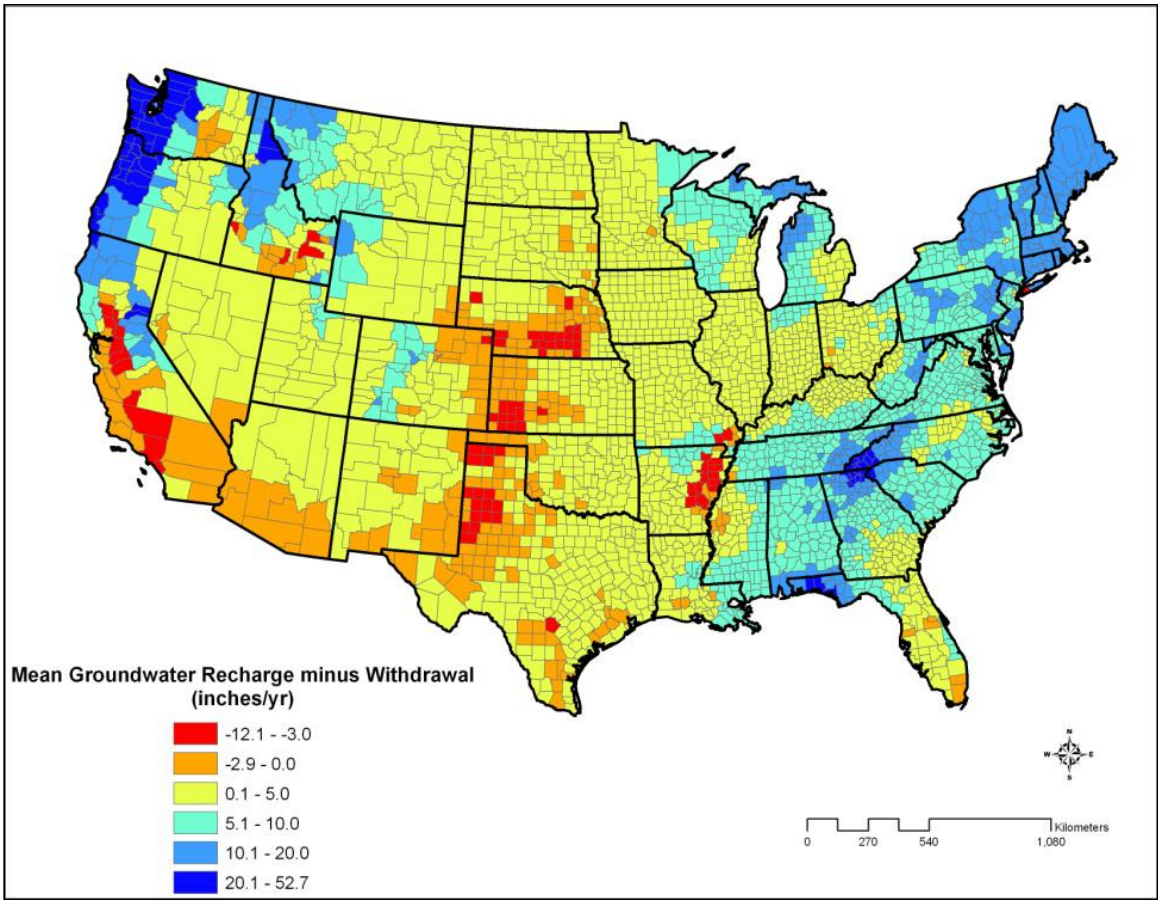


Source: Electric Power Research Institute, *Water Use for Electricity Generation and Other Sectors: Recent Changes (1985-2005) and Future Projection (2005-2030)*, 2011 Technical Report, Palo Alto, CA, November 2011.

Notes: Higher values indicate the extent of water resource development in the area. Values greater than 100 indicate water imports from other counties and/or surface and groundwater storage. Data represent 2005.

Figure 3. Groundwater Use in the Contiguous United States

(difference between recharge and withdrawal)

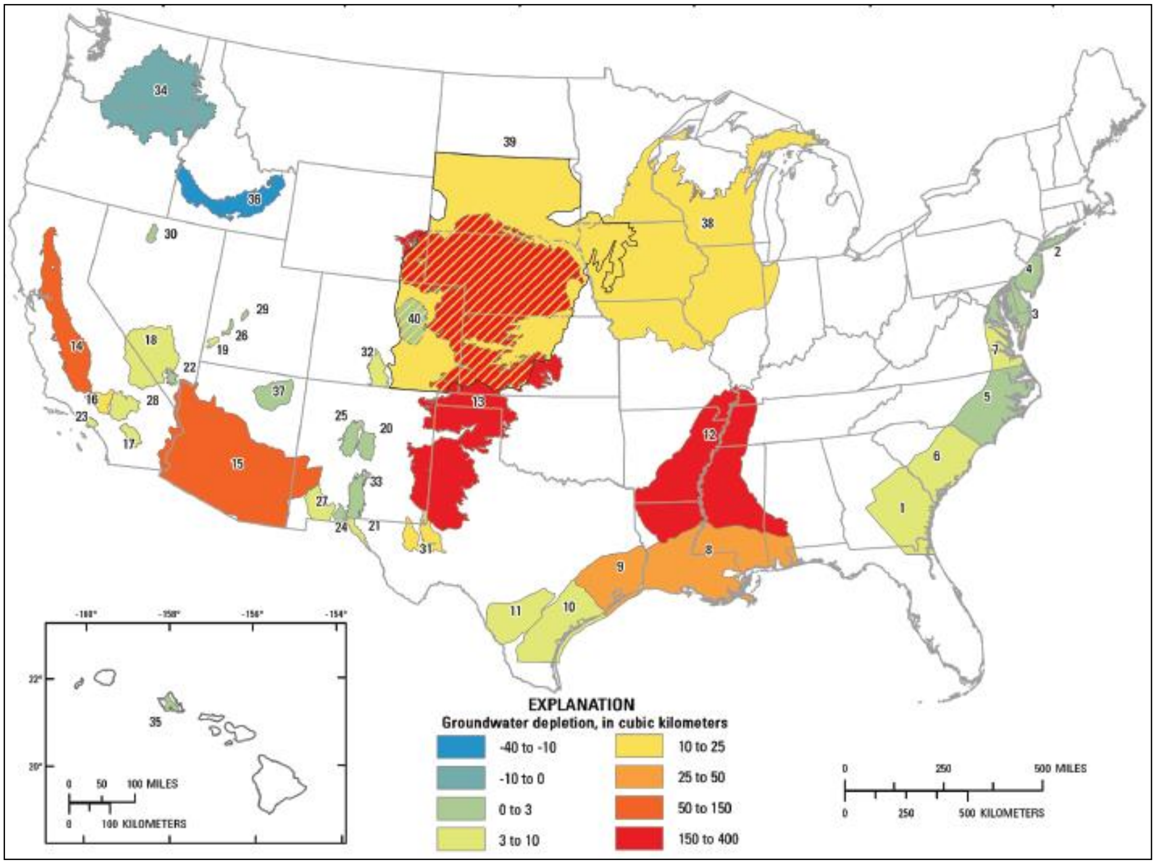


Source: Electric Power Research Institute, *Water Use for Electricity Generation and Other Sectors: Recent Changes (1985-2005) and Future Projection (2005-2030)*, 2011 Technical Report, Palo Alto, CA, November 2011.

Notes: Negative values indicate that an aquifer is being mined at a rate that exceeds its recharge. Data represent 2005.

Figure 4. Cumulative Groundwater Depletion in the United States

(1900 to 2008)



Source: Konikow, L., 2013, "Groundwater depletion in the United States (1900-2008)," U.S. Geological Survey Scientific Investigations Report 2013-5079, 63 p., http://pubs.usgs.gov/sir/2013/5079.

Note: Based on U.S. Geological Survey (USGS) studies of 40 selected aquifers. The USGS excluded Alaska from the map because no substantial groundwater depletion was evident in that state.

Although groundwater and surface water supplies are the most common sources for shale energy development, there is interest in and some use of other supplies. The use of freshwater has raised concern that valuable water resources could be removed from the hydrologic cycle as a result of injection into shale, where the majority of injected water remains bound. Alternative sources of water such as treated industrial and municipal wastewaters or saline groundwater are often technically viable, and used to some degree. However, while the broader use of alternatives to surface water or groundwater is encouraged, economic, regulatory, legal, and technical conditions may limit their adoption.[20] The reuse of some wastewaters (e.g., abandoned mine drainage, produced fluids) as a substitute for freshwater may not only mitigate environmental damage or reduce disposal requirements for these wastewaters, but also reduce freshwater withdrawals. A concern, however, may be that those reusing these wastewaters may face liability risks under federal and state law. Several water source options and related issues are discussed below. Management practices from the American Petroleum Institute (API) stipulate that "whenever

[20] Yoxtheimer, D., S. Blumsack, T. Murphy, 2012, "The Decision to Utilize Acidic Coal-Mine Drainage for Hydraulic Fracturing of Unconventional Shale-Gas Wells," *Environmental Practice* 14:4, 7 p.

practicable operators should consider using non-potable water for drilling and hydraulic fracturing."[21]

Recycled Produced Fluids

The recycling of produced fluids for well operation in hydraulic fracturing has been increasing over the last several years, especially in Pennsylvania. Based on a review of available Pennsylvania Department of Environmental Protection (PA DEP) records, produced fluid recycling increased from approximately 10% in 2009 to 90% by mid-2012. The advent of brine-tolerant friction reducers in slickwater fracking operations has allowed produced fluid reuse without compromising the effectiveness of well completions. Where produced fluids are being recycled in subsequent fracturing activities, the volume of recycled water may constitute between 10% and 30% of the total fluids composition. The Susquehanna River Basin Commission's (SRBC's) estimates indicate that approximately 70% of Marcellus wells recycled some produced fluids for hydraulic fracturing purposes. An increasing reuse trend is also occurring in other states such as Texas and Colorado, where water resources are scarcer. For example, in Colorado some operators indicate that all produced fluids were reused in hydraulic fracturing operations in the Piceance Basin.[22] In Texas, the percentage of produced water reuse varies by shale play, from 0% reuse in the Eagle Ford to 5% in the Barnett in 2011.[23]

Abandoned Mine Drainage

Use of discharge from abandoned mine drainage (AMD) in hydraulic fracturing applications has been limited. While AMD use has been employed by some operators where feasible, a number of technical, economic, and legal constraints have limited its use.[24] From a practical standpoint, the location of an AMD source must be sufficiently close to development activities to allow cost-effective transportation to well site(s), as shown in **Table 1**. Additionally, AMD chemistry must be carefully considered, as there is the potential for downhole precipitation of metals with sulfates that could cause fracture plugging and potentially impede gas flow and production. Therefore, the use of AMD, even from active discharge sites, may require treatment or at least significant dilution prior to use to minimize fracture-plugging potential.

Use of AMD for fracturing would face many challenges. Some abandoned mines have a clear line of ownership and liability for contamination of pristine waters with acidic mine drainage. In Pennsylvania, under the state's Clean Streams Law, waters from these mines must generally be treated to drinking-water quality before being released to streams. Other mines (referred to as "abandoned mines") do not have such a clear line of ownership and liability because the operators have ceased to exist. Waters from abandoned mines could potentially be captured for fracturing; however, potential liability under federal[25] and state laws likely would discourage use of AMD

[21] Cited in Nathan Richardson et al., *The State of State Shale Gas Regulation*, Resources for the Future, May 2013, p. 41.

[22] Colorado Oil and Gas Association, 2011, *Produced Water Fast Facts*; U.S. EPA, 2011, *Proceedings of the Technical Workshops for the Hydraulic Fracturing Study: Water Resources Management*.

[23] Nicot, J.P., Reedy, R.C., Costley, R.A., and Huang, Y., 2012, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report*, prepared for Texas Oil & Gas Association, Austin, TX.

[24] Yoxtheimer, D., S. Blumsack, T. Murphy, 2012, "The Decision to Utilize Acidic Coal-Mine Drainage for Hydraulic Fracturing of Unconventional Shale-Gas Wells," *Environmental Practice* 14:4, 7 p.

[25] Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), any party drawing AMD water from an abandoned mine may be considered an "operator" and subject to the law's liability provisions. Parties could also be in violation of the Clean Water Act for any unpermitted discharges of AMD water to surface

waters. Under Pennsylvania's Clean Streams Law, for example, any company engaged in the transportation and treatment of waters from abandoned mines would assume liability in the case of spillage or other infiltration into waterways. This is a potential disincentive for oil and gas operators to tap AMD from abandoned mines. One company (Seneca Resources), however, has begun a trial of limited AMD utilization in an area of northern Pennsylvania.[26]

Industrial and Municipal Wastewaters

Industrial wastewaters have the potential for use in fracturing operations where water is of compatible quality. Since each source of wastewater will have its own characteristics, these opportunities are evaluated on an individual basis. In addition, the location of the industrial wastewater with respect to drilling operations must be considered. Treated municipal wastewater may be used for well development (as well as having a number of other potential reuse applications outside of the oil and gas sector); this waste stream is typically treated to predictable levels that would be suitable for fracturing operations. As of 2012, there were three municipal treatment plants with the permitting approval to provide effluent to the shale gas industry in Pennsylvania. The Texas Commission on Environmental Quality reported approximately 30 industrial and municipal treatment facilities as of June 2012 that provide water to the industry.[27]

Costs Associated with Water Inputs

Water sourcing, transport, and storage practices utilized in shale energy development have been rapidly evolving to increase overall operational efficiency. Transportation from a source to a well site represents a substantial portion of water-related costs, as shown in **Table 1**; therefore, proximal source location with innovative water transfer methods increases cost-effectiveness.

Table 1. Per-Well Cost for Freshwater Sourcing and Transport

(Marcellus Shale region)

Variable	Value
Volume required	11 million to 22 million liters
Per-unit water procurement costs	$1.25 to $5.00 per 1,000 liters
Truck transportation costs	$5.60/hour per 1,000 liters
Impoundment costs	$6.25 per 1,000 liters
Total cost for a single well	$13.80 to $17.75 per 1,000 liters

Source: Yoxtheimer et al., 2012, "The Decision to Utilize Acidic Coal-Mine Drainage for Hydraulic Fracturing of Unconventional Shale-Gas Wells," *Environmental Practice* 14:4, 7 p.

Water Transport and Storage

As shown above, transfer of water from source to site, as well as water storage, can be a significant operational cost. This section reviews common practices for the transportation of freshwater and produced water.

waters.

[26] State Impact Pennsylvania, 2013, "Using Abandoned Mine Drainage to Frack," available at http://stateimpact.npr.org/pennsylvania/2013/03/12/using-abandoned-mine-drainage-to-frack/.

[27] Ibid.

Water Intake Systems

A surface water withdrawal intake typically consists of a centrifugal or submersible pump installed at a stream, river, or lake withdrawal point that has been properly permitted. The intake structure itself must not be obstructive in order to avoid a water hazard. In addition, an intake screen must be utilized to prevent entrainment or impingement hazards for aquatic life. Oftentimes, the system is somewhat modular so that it can be moved for safety reasons such as during a severe flood. Some designs include an intake built into the streambed, which reduces sediment loading over time. Other designs are connected to a stream flow monitoring device to shut down the pump when flows go below permitted levels. Groundwater supply wells can also serve as intake systems, if properly constructed and designed to withdraw a volume of water needed to meet the demands of hydraulic fracturing operations. Challenges associated with the use of groundwater sources may include additional aquifer yield testing requirements for the purposes of permitting, and relatively low yields compared with surface water sources.

Water Trucking

Transportation of water and wastewater by truck represents a significant cost for shale energy water management. Total trucking costs, including fuel, are approximately $90 per hour.[28] Typical truck capacity is about 100 barrels (approximately 16,000 liters), so a well located one hour (round trip) from a freshwater source would require between 700 and 1,400 truck trips, representing $70,000 to $140,000 in transportation costs, or nearly $1 per barrel (roughly half a penny per liter). Thus, assuming all water is trucked in from a location that is a one-hour round trip from the well, water costs to develop a single unconventional shale well would be between $85,000 and $260,000, or between $1.21 to $1.84 per barrel of water ($13.80 to $17.75 per thousand liters). The transportation cost figure scales linearly with distance, while water cost is fixed; therefore, a well that is a two-hour round trip from a freshwater source would incur estimated costs of $2.21 to $2.84 per barrel of water ($27.60 to $35.50 per thousand liters), depending on the cost of water.

Water Pipelines

Direct piping of water from a source to a well-pad impoundment occurs in locations where operational costs are less than water transfer by truck and where pipelines can obviate the challenges and risks of transport by road. Use of pipelines for water transfer minimizes trucking, road damage, and diesel fuel use, and can be approximately 50% less expensive than trucking.[29] Although initial capital costs are typically higher, the costs of installing permanent intakes, water pipelines, and impoundments may be recaptured if reused to serve multiple wells. A demonstration by Seneca Resources showed that an 11-kilometer pipeline and surface water withdrawal intake system would cost $7.2 million, but save about 50% ($9 million) in water transfer costs for fracturing operations at 70 wells.[30]

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[28] Kepler, D., and M. Clinger, 2012, *Managing Costs Through Centralization*, presentation given at the Shale Gas Water Management Initiative, Canonsburg, PA, March 2012.

[29] Ibid.

[30] Ibid.

Centralized Water Storage Impoundments

Once delivered to the well site, water must be stored. Freshwater impoundment construction costs are approximately $1 per barrel, based on industry estimates,[31] which would equate to approximately $119,000 for a 19 million liter (5 million gallon) impoundment. This type of water storage method is fairly common, and can be cost-effective especially where long-term operations are anticipated; however, such impoundments cause significant earth disturbance.

Modular Water Storage

Use of temporary above-ground storage tanks and impoundments occurs more commonly because such structures reduce the surface footprint compared to centralized water storage impoundments. Further, the structures are reusable. An example is vertical steel tanks, which have the advantage of being capable of storing a large volume of fresh or produced water (up to 5 million gallons) in a relatively small area.

Access to Water Sources

The shale energy industry operates within a patchwork of local, state, and federal water management and regulatory regimes. In addition, regional organizations such as river basin commissions (RBCs), where present in areas with shale energy development, have emerged as active players in managing potential conflicts between watershed user groups including agriculture, energy, and public water interests.

State Approaches to Water Management

As shown in **Figure 5**, of 31 states surveyed, 30 regulate surface water and groundwater withdrawals through permits for water withdrawals or registration and reporting, and several states require both permits and registration and reporting.[32] Pennsylvania, for example, requires a water management plan (a full life cycle of the water used in shale gas production), although authority for most decisions is granted to the river basin commissions, except in the western part of the state, which lies outside the river basin commissions' boundaries. Louisiana, as another example, recommends that groundwater used for drilling or fracturing be taken from the Red River Alluvial aquifer. In Texas, surface water withdrawals for oil and gas rig operations require a permit; for groundwater, rig water supply does not generally require a state permit, but must comply with rules (e.g., registering wells, well spacing, well permit) of the respective groundwater conservation district. The rules are established by the districts, and vary widely. In North Dakota, the oil and gas industry accesses some of its water through water depots that are required to obtain relevant surface and groundwater permits. The state also can issue individual oil and gas operators' permits for access to surface and groundwater supplies. For some aquifers that are declining, North Dakota has limited access if other suitable sources are available.

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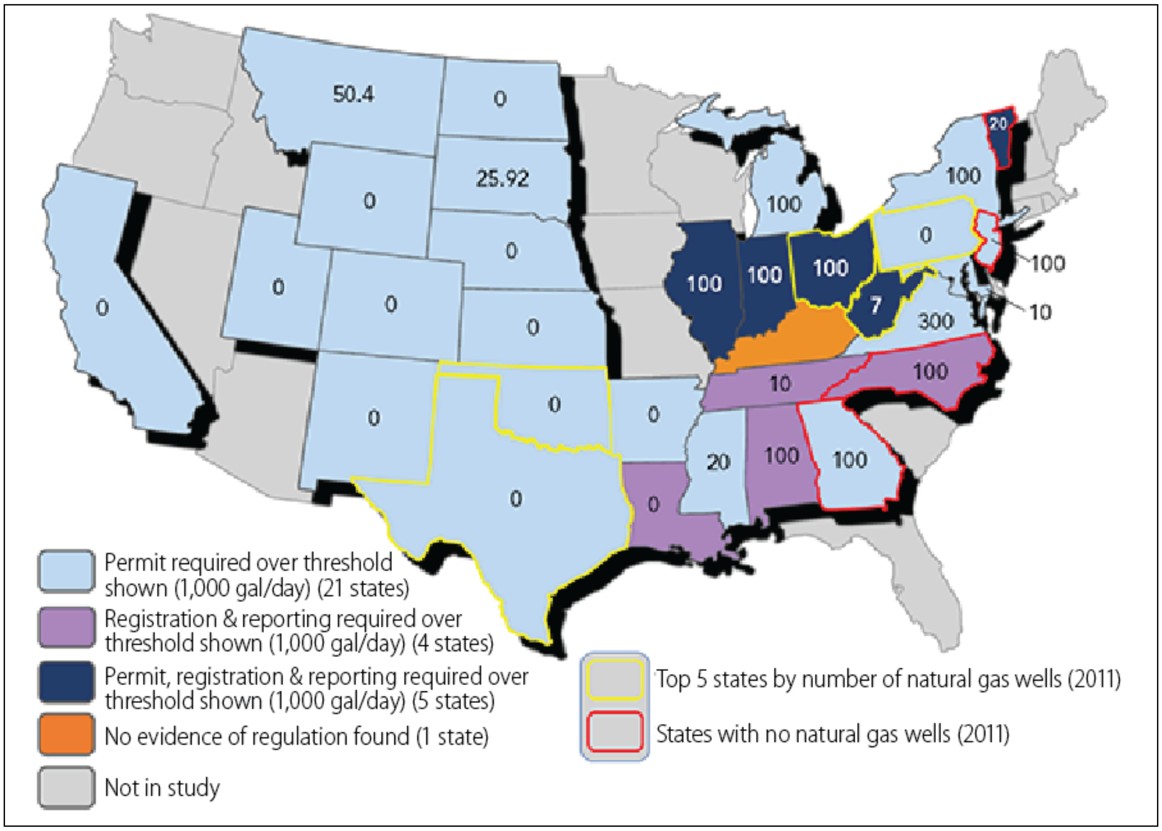
[31] Yeager, 2011.

[32] Nathan Richardson et al., *The State of State Shale Gas Regulation*, Resources for the Future, May 2013, http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx#map.

Figure 5. Lower 48 State Water Withdrawal Regulations



Source: Nathan Richardson et al., *The State of State Shale Gas Regulation*, Resources for the Future, May 2013, http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx#map.

Note: Numbers shown on the states represent the withdrawal thresholds (in thousands of gallons per day) for reporting/permit requirements. Most apply to both groundwater and surface water withdrawals.

River Basin Commissions

Relevant to shale energy development, a number of interstate commissions and compacts are important to the allocation of, and access to, freshwater—principally shared surface waters. Examples include the Susquehanna River Basin Commission (SRBC) and Delaware River Basin Commission (DRBC).[33] River basin commissions may have some authority to both ration water allocations among competing users and request member states to impose mandatory restrictions on "nonessential" water uses (e.g., golf course irrigation, lawn watering, service of water in restaurants, washing of most automobiles, etc.). They may regulate withdrawals (permit review), evaluate seasonal limitations, monitor water quality, tabulate water consumption and reuse, and establish moratoria on drilling to set limits and examine impacts, among other functions. River basin commissions in shale energy regions often have also expanded their research, monitoring, and staffing to meet the challenges of shale energy development.

[33] Abdalla, C.W., Drohan, J.R., and Becker, J.C., 2010, *River Basin Approaches to Water Management in the Mid-Atlantic States*, Penn State University Cooperative Extension Publication, 26 p. The Interstate Commission on the Potomac River Basin (ICPRB) has not yet had to deal with shale gas development demands (due in large part to a moratorium on shale gas development in Maryland).

Wastewater Management: Flowback and Produced Water (Produced Fluids)

Once a well has been fractured and prior to coming on line, approximately 10% to 50% of the injected fluids may be returned to the surface over the course of several days to weeks, depending on the geology of the shale play.[34] These fluids are commonly known as flowback water, and consist primarily of the fluids used to fracture the shale formation. Flowback water is different from naturally occurring water in shale formations ("produced water") that typically is also brought to the surface following well completion. The produced formation water can be highly saline, and often is referred to as produced brines.

At some point, water recovered from a natural gas well will transition from mostly flowback water to mostly produced water.[35] In produced water, total dissolved solids (TDS) values range widely by shale play, from approximately 13,000 to more than 280,000 milligrams per liter (mg/L), with an average range of 13,000 to 120,000 mg/L, and can range as much as 120,000 to more than 280,000 mg/L within a play, as shown in **Table 2**. Produced waters may also contain constituents that are leached out from the shale formation, including barium, calcium, iron, and magnesium, as well as naturally occurring dissolved hydrocarbons and naturally occurring radioactive materials (NORM).

Flowback water, shown in **Figure 6**, typically has elevated concentrations of TDS, which may include salts, metals, clays, and fracturing fluid chemical additives. The concentration of salts in flowback water increases rapidly during the first week or two after well completion. No clear demarcation exists between the two fluid flows. Proper storage and management of these fluids can prevent the potential contamination of groundwater and surface water that would occur if released into the environment.

During the production phase of a well, some portion of the injected fluids in the shale formation may slowly flow out of the well as part of the produced water, along with natural gas or oil, typically at a rate of up to a few barrels per day, with the rate decreasing slowly over time (see **Figure 7**). The mixture of flowback and produced water is referred to in this report as "produced fluids."

Table 2. Salinity of Produced Water from Different U.S. Shale Formations

Shale Formation	Average TDS (PPM)	Maximum TDS (PPM)
Fayetteville	13,000	20,000
Woodford	30,000	40,000
Barnett	80,000	>150,000
Haynesville	110,000	>200,000
Marcellus	120,000	>280,000

[34] Acharya, H.A., Henderson, C., Matis, H., Kommepalli, H., Moore, B., Wang, H., 2011, *Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use*, U.S. Department of Energy: DE-FE0000784 Final Report.

[35] Eric Schramm, *What is Flowback, and How Does it Differ from Produced Water?*, Institute for Energy and Environmental Research of Northeastern Pennsylvania Clearinghouse website, March 24, 2011, http://energy.wilkes.edu/pages/205.asp.

Source: Acharya, H.A., Henderson, C., Matis, H., Kommepalli, H., Moore, B., Wang, H., 2011, *Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use*, U.S. Department of Energy: DE-FE0000784 Final Report.

Notes: TDS is total dissolved solids. PPM is parts per million (for reference, 10,000 ppm is equivalent to 1%). In this Department of Energy report, the authors refer to all returning water after hydraulic fracturing as "flowback," and do not differentiate between fracking fluid "flowback" and "produced water."

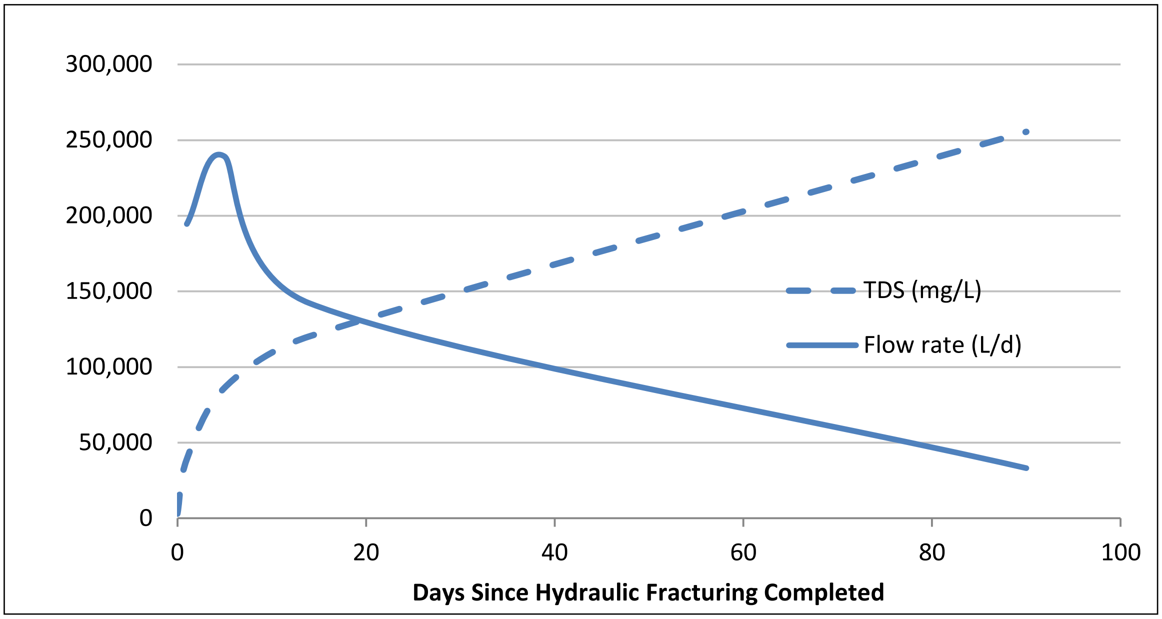
Figure 6. Photograph of Flowback Water, Treated Flowback Water Ready for Reuse, and Produced Water

From left to right: Flowback water, treated flowback water ready for reuse, and produced water

Source: Earth and Mineral Sciences Energy Institute, Pennsylvania State University.

Figure 7. Change in the Total Dissolved Solids Concentration of Produced Fluids over Time

(example of a Marcellus Shale well)



Source: Earth and Mineral Sciences Energy Institute, Pennsylvania State University.

Notes: Values on the Y axis reflect mg/L, which refers to milligrams per liter, for the TDS curve, and L/d, which refers to liters per day for the flow rate curve. For example, on day 20, where the curves intersect, the concentration was approximately 130,000 mg/L, and the flow rate was approximately 130,000 L/d.

Practices for managing produced fluids vary widely by operator and by location. There is no identifiable set of best practices for water management for the shale gas or shale oil sectors as a whole. In Texas, for example, injection wells are widely utilized for wastewater disposal, whereas geologic disposal is utilized less frequently in the Appalachian region. Wastewaters from shale energy wells in the Appalachian region are more likely to be managed using a combination of underground injection, surface disposal (such as impoundments), onsite treatment and blending for reuse or transport to water treatment plants for reuse, surface discharge, or other disposal. Surface disposal represents one of the lowest-cost ways to manage wastewaters from shale energy projects, but also introduces contamination pathways if impoundments are not properly constructed or managed. Hauling of water by truck to treatment facilities (or to geologic disposal wells if these wells are not located close to production areas) is among the highest-cost management strategies, and introduces potential contamination pathways if spills or other incidents occur during the transportation process.

Proper management of fluids derived from drilling and hydraulic fracturing operations remains a substantial environmental management challenge. Many operators have significantly improved their management of fluids by utilizing advances in technologies such as lining well pads to capture releases, using closed loop drilling systems, and recycling flowback and produced fluids. Continued improvement in fluids management practices is likely as companies further refine their operations to meet environmental challenges and regulatory requirements.

New treatment and reuse technologies are currently being deployed to further refine the treatment and recycling of flowback and produced fluid. Deep underground injection wells (referred to as

Class II wells under the federal Underground Injection Control (UIC) program)[36] are used to dispose of the portion of oil and gas wastewaters not recycled or sent to other locations for off-site treatment and disposal. Treatment and reuse technologies and practices for water sourcing, transport, and storage vary by operator and region. In addition, cost is always a consideration in fluid management practices. **Table 3** shows a range of costs associated with a variety of produced fluid treatment methods.

Table 3. Comparative Costs for Produced Fluid Management in Shale Energy Development

Treatment Method	$ per 1,000 gallons
Surface disposal	0.07
Deep injection well—existing	0.66
Evaporation/infiltration pond with spray	0.99
Spray irrigation	1.08
Microfiltration	1.36
Evaporative pond—lined-spray	1.97
Electrocoagulation	2.00
Shallow injection/aquifer renewal	2.85
Evaporative pond/infiltration	2.98
Water hauling	4.82
Deep injection well—new	5.64
Nano-filtration	6.15
Reverse osmosis	6.94
Evaporative pond—lined	27.56

Source: U.S. Department of Energy National Energy Technology Laboratory Project DE-FE0001466, 2012.

While disposal is a common management approach, others are seeking to identify ways to beneficially use these waste streams. The commercial or public-sector use of certain produced fluids, for example, is being permitted in Pennsylvania and West Virginia. That is, if the brines meet specified water quality requirements, they are being applied in winter to treat roadways in those states, rather than being disposed of geologically or treated in designated facilities.[37] Identification of uses for waste materials that may be considered beneficial could be important to

[36] The Safe Drinking Water Act of 1974 (SDWA; P.L. 93-523), as amended, directed EPA to establish an underground injection control (UIC) regulatory program to protect underground sources of drinking water. UIC provisions are contained in SDWA Part C, §§1421-1426; 42 U.S.C. §§300h-300h-5. Class II injection wells discussed here are those wells used for disposal of brines and other wastewater associated with oil and gas production (Class IId).

[37] For example, a 2010 Memorandum of Agreement between the West Virginia Division of Highways and the West Virginia Department of Environmental Protection allows the beneficial use of gas-well brines within the state for roadway anti-icing and deicing. http://www.dep.wv.gov/WWE/Documents/WVDOHWVDEP%20Salt%20Brine%20Agreement.pdf. Reuse of brines for road treatment also may pose some runoff or infiltration risks to nearby freshwater bodies or aquifers, which have raised interest in identifying best practices for minimizing such risks.

the process of designing regulatory frameworks that will allow drilling companies and potential users of materials that would otherwise be considered waste streams to make better decisions.

Underground Injection Disposal Wells

Deep well injection is regulated under the authority of the Safe Drinking Water Act Underground Injection Control (UIC) program, and is a common disposal method for a variety of waste fluids, including oil and gas wastes that are primarily produced waters (i.e., brines). Oil- and gas-related injection wells are classified as Class II injection wells. There are approximately 151,000 Class II injection wells in the United States, 80% of which are used for enhanced oil recovery and 20% of which are used for disposal of wastes.[38] Collectively, Class II wells accept an estimated 2 billion gallons of brine per day. The special class of oil and gas waste fluid disposal wells is collectively known as Class IId UIC wells. There are more than 30,000 such wells in the United States today, though the distribution of these wells among shale drilling areas is uneven. Texas hosts approximately 52,000 Class II injection wells, of which approximately 10,000 are disposal wells. Hence produced water recycling rates in Texas are generally less than 10%.[39] In contrast, the Appalachian Basin contains a limited number of Class IId injection wells, apparently due in part to the lack of suitable injection reservoirs with sufficient depth and permeability to accept significant volumes of waste, but also partly because of a lack of need for such disposal capacity before the emergence of shale gas. Through 2013, Ohio had approximately 180 active Class IId wells, while Pennsylvania had eight active disposal wells. Regulatory differences and policy issues also can play a role in well permitting.[40]

Example: The Marcellus Shale Play

Two questions important to the future development of shale energy resources in the Marcellus play, as well as other shale plays around the nation, are the following:

1. What is the volume of produced fluids projected to be generated over time?
2. What is the available long-term disposal capacity?

The available Pennsylvania Department of Environmental Protection (PA DEP) Marcellus gas and produced fluids records (from mid-2009 through mid-2012) were reviewed to evaluate this issue.[41] The volume of Marcellus Shale produced fluids and the associated portion disposed of via injection wells were compared to the available gas production records. Records from the first half of 2012 indicate that a total of eight barrels of produced fluids were generated for each million cubic feet of produced gas. Of the eight barrels of produced fluids, approximately 1.1 barrels were disposed of via injection wells.

[38] U.S. Environmental Protection Agency, *Class II Wells—Oil and Gas Related Wells*, http://water.epa.gov/type/groundwater/uic/class2/index.cfm.

[39] Nicot, J.P., Reedy, R.C., Costley, R.A., and Huang, Y., 2012, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report*, prepared for Texas Oil & Gas Association, Austin, TX.

[40] See, for example, J. D. Arthur, Stephen L. Dutnell, and David B. Cornue, *Siting and Permitting of Class II Brine Disposal Wells Associated with Development of the Marcellus Shale*, Society of Professional Engineers, SPE 125286, September 2009.

[41] Pennsylvania Department of Environmental Protection, Office of Oil and Gas Management, Production Records accessed October 2012, available at https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx.

Of the total produced fluids from all Pennsylvania oil and gas operations, 97% were disposed of in injection wells in Ohio.[42] **Figure 8** shows the change in volume between 1997 and 2012 of produced fluids injected into Ohio wells, indicating the rapid increase since about 2008. **Figure 9** shows the projected volume of fluids that may be generated from Marcellus Shale gas development in Pennsylvania based on trends from existing data, assuming a 5.2% annual increase in Marcellus gas production, as predicted by the U.S. Energy Information Administration (EIA).[43] Also shown in **Figure 9** is the current case of 1.1 barrels of produced fluids injected into UIC wells for each 1 million cubic feet of gas produced when 90% reuse is occurring. In addition, hypothetical scenarios are shown with an assumed 0.55 barrels and 2.2 barrels for each 1 million cubic feet of produced gas, and similar scenarios assuming only 2.6% year-over-year growth in Marcellus gas production.

Many factors can influence the volume and management of shale gas produced fluids. Lower-volume scenarios could result for a variety of reasons, such as low natural gas prices that might discourage the drilling of new wells and prevent previously drilled wells from being brought into production. New technologies may allow for more economical treatment and reuse of produced fluids, thus decreasing the percentage of the total amount produced sent for injection.

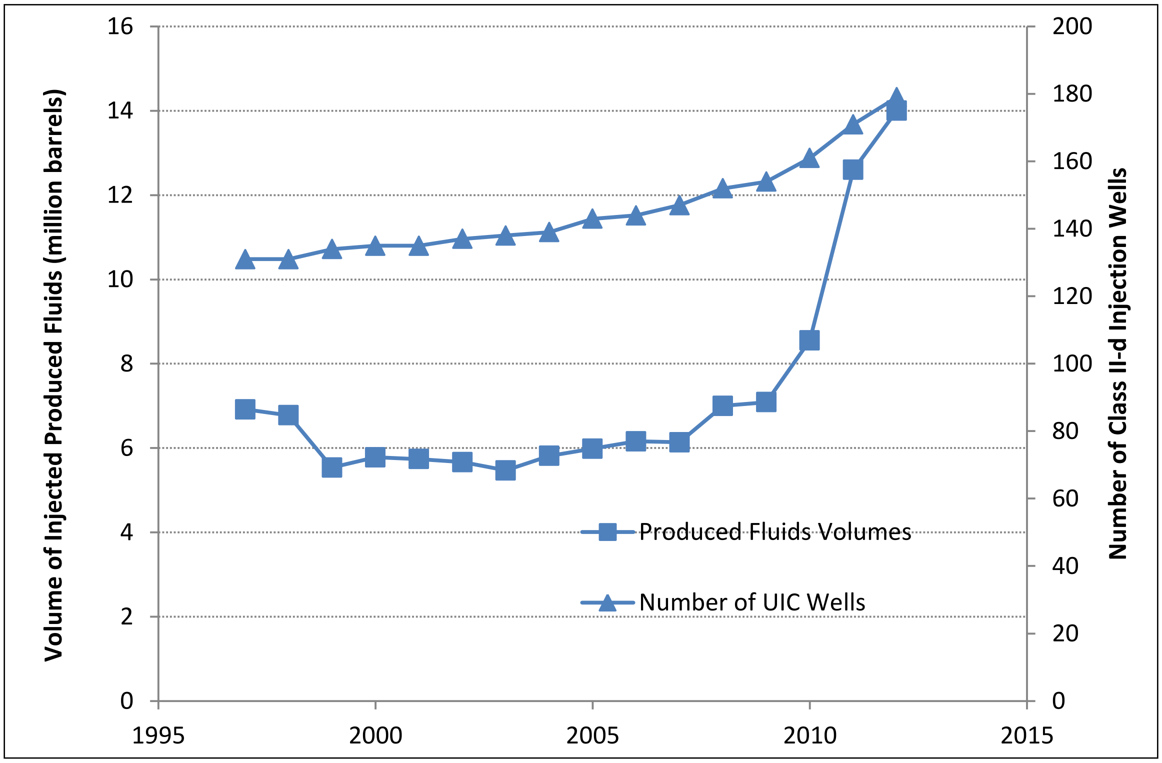
One significant unknown variable is the ultimate disposal capacity in Ohio, Pennsylvania, West Virginia, and New York. If it is assumed that 1.1 barrels of produced water are injected into disposal wells per million cubic feet of produced gas, then the volume of produced fluids requiring injection well disposal is projected to be 3.3 million barrels of Marcellus produced water (138 million gallons) from Pennsylvania alone by 2022. This would represent a 65% increase in injection well use as compared to the rates for the first half of 2012. The 179 injection wells used in Ohio (including 40 new wells brought on line over the last decade) were apparently able to handle an increase of approximately 6 million barrels (252 million gallons) annually over the course of a decade. In addition to possible limitations on capacity to inject all of the produced fluids if natural gas-related activities continue at the current pace or increase, the increased scrutiny on a possible link between injected fluids and earthquakes (discussed below) may also constrain the ability to install injection wells to handle all the disposal needs.

[42] Pennsylvania Department of Environmental Protection, Office of Oil and Gas Management, Production Records accessed October 2012, available at https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx.

[43] U.S. Energy Information Administration, 2012, *Annual Energy Outlook 2012*.

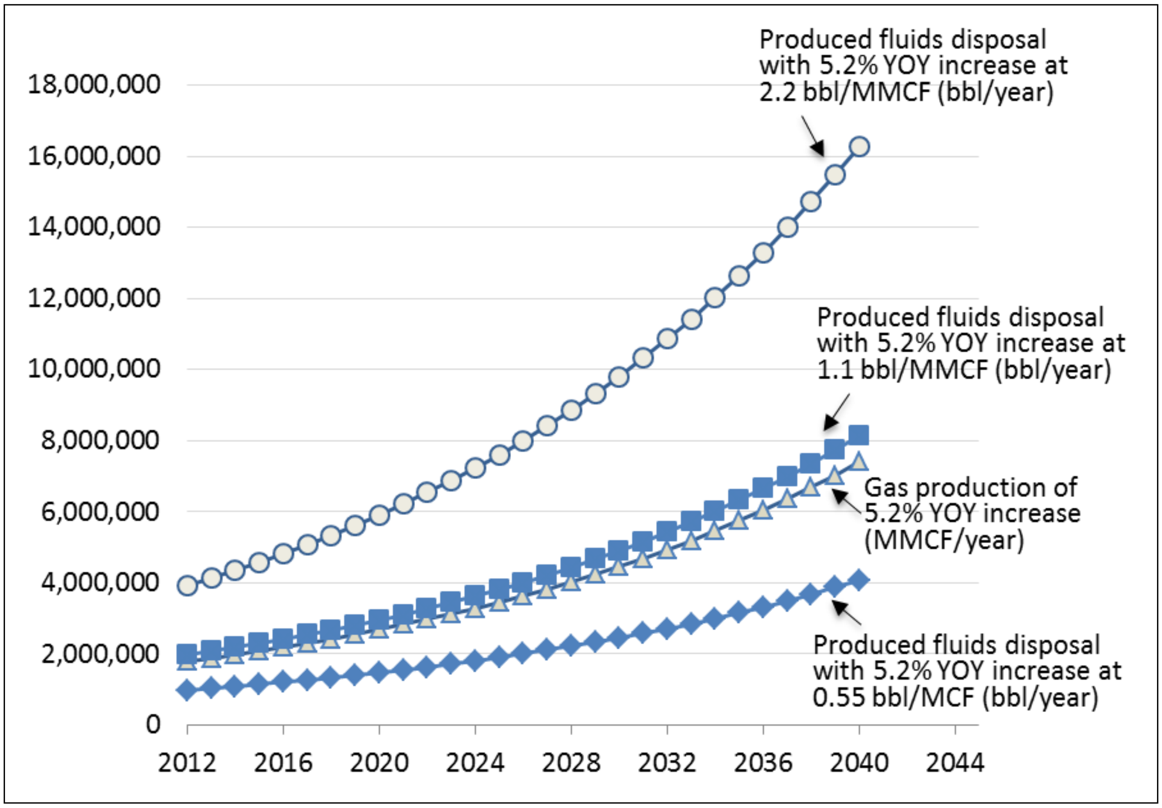
Figure 8. Ohio's UIC Disposal Well Activity, 1997-2012

(volume of produced fluids injected and number of UIC wells)



Source: Ohio Department of Natural Resources (OH DNR), 2012. Underground injection well data provided by Tom Tomastik, OH DNR Underground Injection Control Program Manager.

Figure 9. Projected Fluids from Marcellus Shale Gas Development in Pennsylvania



Source: Earth and Mineral Sciences Energy Institute, Pennsylvania State University.

Notes: Based on trends from existing data, as well as projected increases of 2.6% and 5.2% annually in Marcellus gas production. YOY means year-over-year.

Related Issues: Induced Seismicity and Abandoned Wells

Potential for Induced Seismicity

Induced seismicity[44] is not a concern related to surface or groundwater resources, per se, but has been raised as a potential issue. While fracturing itself involves induced seismicity, such events are localized and of very low amplitude (10^{-2} on Richter scale); they generally cannot be felt at the surface. Reports of minor earthquakes possibly induced by fracturing occurred in Garvin County, OK, in 2011,[45] but no definitive connection to fracturing per se has been made. There is, however, a potential for induced seismicity anywhere that wastewater is pumped into deep rock

[44] Induced seismicity refers generally to earthquakes that result from human activity. These are typically small tremors that are not felt at the Earth's surface, and which could result from mining activities, filling of large water reservoirs behind dams, and as discussed in this report, from injection of waste fluids from oil and gas activities. Some of the earthquakes from deep well disposal have been large enough to be felt and cause minor damage on ground surface. Typically, microearthquakes caused by the hydraulic fracturing process itself are too small to be felt or cause damage.

[45] Holland, A., 2011, *Examination of possibly induced seismicity from hydraulic fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey Open File Report OF1-2011, 28 p.

units at high rates,[46] regardless of regional geologic contrasts.[47] One theory suggests that "fluid injection may trigger earthquakes if pressures, rates, and permeability are sufficient to allow fluid to reach a favorably oriented fault and reduce the normal stress, decreasing fault strength."[48] The potential depends on a number of factors, including (1) the state of subsurface stresses (i.e., whether stress buildup has been relieved by previous earthquakes); (2) the presence or absence of through-going faults; (3) porosity and permeability (transmissivity of fluids) of the unit into which fluids are being pumped; and (4) the rate at which fluids are being pumped and the relative pressure differential developed. It is likely that induced seismicity has occurred in what are generally considered "stable" tectonic regions (compared to, for example, portions of California), including eastern Ohio, Oklahoma, and Arkansas.[49]

Earthquakes with magnitudes as high as 4.8 have been measured in some regions where the injection of wastewater from drilling/completion activities occurs. One example is a series of earthquakes in the Dallas-Ft. Worth area (Barnett Shale) that has been linked to underground injection wells.[50] In 2011, a series of low-magnitude earthquakes (magnitude 2.1 to 4.0) were recorded in the Youngstown, OH, area. This seismic episode was not itself caused by fracturing, but was linked to the operation of a UIC Class II disposal well that was used to dispose of wastewater from Marcellus Shale drilling in Pennsylvania. Following the incident, the disposal well was shut down.[51]

Abandoned/Orphaned Wells

Abandoned oil and gas wells are a concern in some areas of active shale energy extraction, because intersection with previously unmapped wells provides a potential pathway for migration of methane or fluids into groundwater. In particular, "orphaned" wells, those that are defined as inactive/abandoned oil and gas wells with no responsible party to properly plug the well and restore the location, are of concern because their location and status are often unknown. Abandoned wells must be plugged to permanently seal the inside of the well and wellbore (typically above and within producing zones and across freshwater aquifers) so that fluid cannot migrate from deeper to shallower zones or create reservoir problems through downward drainage. The plugging process involves the placement of cement and other materials, such as gels or

[46] National Research Council, 2012, *Induced Seismicity Potential in Energy Technologies*, National Academy of Sciences, 300 p. Also, there are nearly 150,000 Class II (brine) injection wells in the United States.

[47] See Zoback, M. L., and M. D. Zoback, 1980, "State of stress in the conterminous United States," *Journal of Geophysical Research*, 85, B11, pp. 6113-6156, http://dx.doi.org/10.1029/JB085iB11p06113; and Zoback, M., 2012, "Managing the seismic risk posed by wastewater disposal," *Earth*, American Geological Institute, http://www.earthmagazine.org/article/managing-seismic-risk-posed-by-wastewater-disposal.

[48] Frohlich, C., 2012, "A survey of earthquakes and injection well locations in the Barnett Shale, Texas," *Leading Edge*, 1446-1451.

[49] For an overview of the scientific understanding of induced seismicity in the United States as of July 2013, see William L. Ellsworth, "Injection-induced Earthquakes," *Science*, vol. 341 (July 12, 2013).

[50] See Frohlich, C., Hayward, C., Stump, B., and Potter, E., 2011, "The Dallas-Fort Worth Earthquake Sequence: October 2008 through May 2009," *Bulletin of the Seismological Society of America*, 101(1), pp. 327-340; Frohlich, C., 2012, "A survey of earthquakes and injection well locations in the Barnett Shale, Texas," *Leading Edge*, pp. 1446-1451; and Shemeta, J.E., Eide, E.A., Hitzman, M.W., Clarke, D.D., Detournay, E., Dieterich, J.H., Dillon, D.K. Green, S.J., Habiger, R.M., McGuire, R.K., Mitchell, J.K., Smith J.L., Ortego, J.R., and Gibbs, C.R., 2012, "The potential for induced seismicity in energy technologies," *Leading Edge*, Society of Exploration Geophysicists, v. 31, no. 12, pp. 1438-1443.

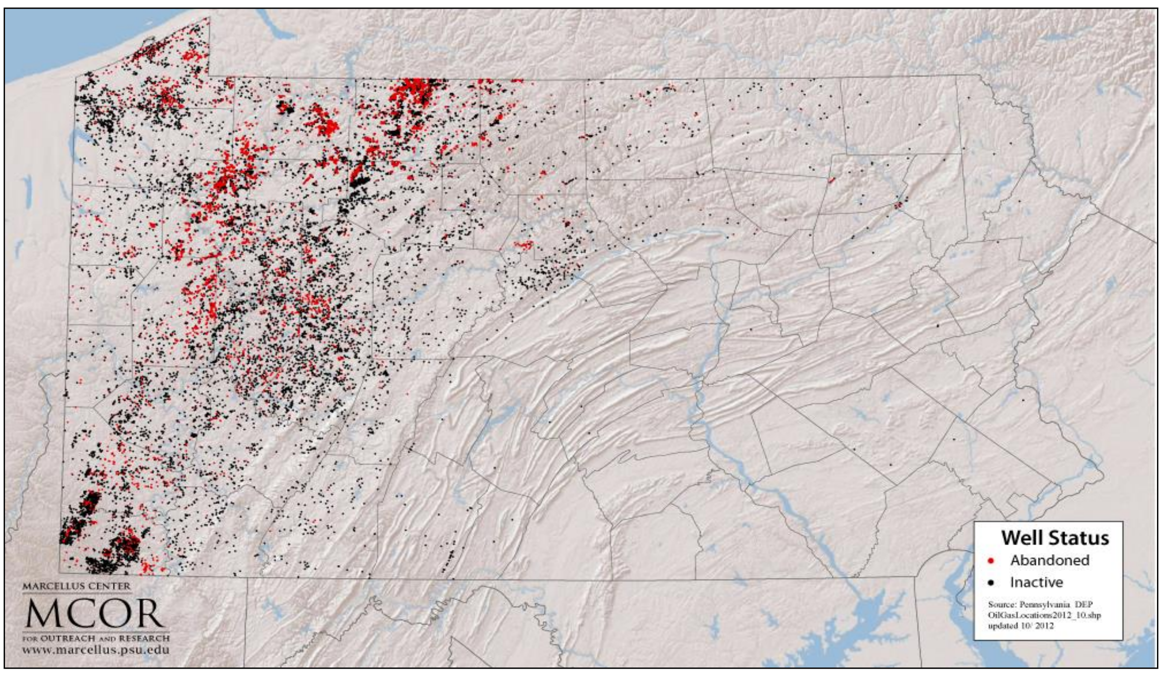
[51] Ohio Division of Natural Resources, 2012, *Preliminary Report on the Northstar Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area*, 24 p.

bentonitic mud, within the wellbore and production casing in a manner that prevents the upward or downward migration of formation fluids. All oil and gas producing states now regulate well plugging; most have standards for cement quality, and most require advance notice so that regulatory personnel can witness operations to assure proper plugging.[52]

Regional Concern in the Marcellus Shale and Utica Shale Plays

In addition to the sheer number of abandoned wells, many such wells were drilled prior to requirements for regulation, permitting, and record-keeping, or when those requirements were less stringent than current requirements. For example, the first well in Pennsylvania was drilled in 1859, and the first requirement to plug was issued in the 1890s. Pennsylvania first imposed regulation of oil and gas wells in 1955. The state issued permits to drill through coal seams in 1956, and for the drilling of all wells in 1963. The Pennsylvania Oil and Gas Act of 1984, which took effect in 1985, required the registration of all wells that were not previously permitted. Nonproducing wells were required to obtain an inactive regulatory status or be plugged. Pennsylvania has documented nearly 34,000 preregulatory wells, but estimates suggest that the total number may approach 200,000 wells (see **Figure 10**).

Figure 10. Known Abandoned and Inactive Wells in Central and Western Pennsylvania



Source: Marcellus Center for Outreach and Research, based on Pennsylvania Department of Environmental Protection data as of October 12, 2012.

Note: Approximately 9,000 wells shown; as many as 200,000 additional wells may exist.

Wells that may not have been properly plugged and cased can be a source of methane migration from gas-bearing strata at somewhat greater depth to the surface and/or into freshwater aquifers. A number of abandoned wells in Pennsylvania penetrate rock strata to the Oriskany Sandstone

[52] *State Oil and Gas Regulations Designed to Protect Water Resources*, 2009, U.S. Department of Energy National Energy Technology Laboratory and Groundwater Protection Council, 62 p.

below the Marcellus Shale. Numerous instances of methane migration to private water wells have been linked to nearby abandoned wells.[53] Such wells, when unknown, are also a potential danger when further drilling occurs nearby. A previously unmapped well blew a geyser of methane gas and water up to 30 feet in the air in June 2012 in Tioga County, PA (in the northeastern part of the state), during drilling of a Marcellus Shale well.[54] Orphan wells likely contribute significantly to the flux of methane to the atmosphere, providing an additional, untallied source of greenhouse gases. A more detailed discussion of the relative contribution of greenhouse gases to the atmosphere from orphaned wells is beyond the scope of this report.

Responsibility for the management of abandoned and orphaned wells typically falls to state authorities. In Pennsylvania, for example, wells fall under the jurisdiction of the Pennsylvania Department of Environmental Protection (PA DEP). Under that state's well plugging program, 2,948 wells had been plugged through 2013.

Emerging Water Technologies for Shale Energy Development

The pace of technological change in water sourcing and water management for shale energy development is rapid, but uneven. Trends in water management have generally been influenced by local disposal costs, regulations, and geologic conditions, rather than by water scarcity alone. Some regions, particularly those where regulations restrict the discharge of wastewater to surface waters, and which have relatively few options for wastewater disposal (due to a combination of geologic and regulatory factors), have seen shifts toward closed-loop water management systems that utilize recycled flowback water extensively and minimize the use of disposal wells. These systems have also been used more extensively, and by necessity (because of a lack of wastewater injection wells), in emerging unconventional production areas such as the Marcellus Shale play than in regions with recent growth in shale development, but that have a long history of active oil and gas production, such as Texas.

This section discusses the status of emerging technology options for reducing the potential impacts of shale energy activities on groundwater and surface water resources. Much of the research is being conducted by private industry, often in close partnership with government agencies and university scientists.

Technology Options for Drilling and Completing Wells

At the drilling, completion, and production phases of the shale energy well life cycle, a number of alternatives to conventional water-utilization systems are being implemented. These include

- *nontoxic or "green" fracturing fluid additives*, driven in part by concerns over the composition of fracturing fluids and increasing requirements of disclosure of fracturing fluid composition;
- *alternatives to freshwater in the fracturing process*, including recycled flowback fluids (mixed at various proportions with freshwater), carbon dioxide, nitrogen,

[53] Pennsylvania Department of Environmental Protection (PA DEP), 2009, *Stray Natural Gas Migration Associated with Oil and Gas Wells*; PA DEP: Harrisburg, 2009, http://www.dep.state.pa.us/dep/subject/advcoun/oil_gas/2009/Stray%20Gas%20Migration%20Cases.pdf; Pittsburgh Geological Society, *Natural Gas Migration Problems in Western Pennsylvania*.

[54] http://stateimpact.npr.org/pennsylvania/2012/10/10/perilous-pathways-behind-the-staggering-number-of-abandoned-wells-in-pennsylvania/.

hydrocarbon gases (such as ethane and propane), industrial waters, and (in the Appalachian region) potentially acid mine discharge waters;

- *innovative well and well-pad configurations* such as multilateral wells, which, in some cases, reduce the total volume of fluids required, but are more likely to have economic advantages in reducing labor, trucking, and other water handling costs; and
- *closed-loop or reduced emission ("green") well completions* for handling flowback fluids and minimizing the venting of methane to the atmosphere.

These innovations are at various stages of maturity. Continued deployment of these innovations may be driven by a mix of project economics and regulatory influences (such as regulations regarding closed-loop completion systems that will be required for many shale energy projects beginning in 2015).[55] Some of these innovations, such as closed-loop completions, are becoming commonplace in many producing regions, while others, such as nontoxic additives and alternative fracking fluids, need additional demonstration and validation before being accepted more broadly by industry.[56]

Nontoxic Hydraulic Fracturing Fluid Additives

New additives and transparent reporting of chemical additives to hydraulic fracturing fluids,[57] regardless of their toxicity, are already being applied in some cases. Companies such as Halliburton, Schlumberger, Baker-Hughes, and others already have them available and are continuing to develop new additives, according to their individual reports on websites and investor circulars.[58] In Pennsylvania, industry is now required to report types and volumes of additives on the FracFocus website.[59] Pennsylvania joins Texas, Colorado, Arkansas, Montana, Michigan, and other states requiring some level of disclosure of volume or composition of fracking fluids, or both. This trend toward nontoxic additives (referred to as "green" fracking fluids) has the potential to provide greater protection for workers and lowered impact of spills on surface waters, soils, and shallow groundwater.[60]

[55] Closed loop, or reduced emission completions (RECs), is a term used to describe a practice that captures air pollutants and gas produced during well completions or well workovers following fracturing. In 2012, EPA issued regulations under the Clean Air Act that require the use of RECs on hydraulically fractured natural gas wells beginning in 2015. See U.S. EPA, *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells*, http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.

[56] Performance is an important issue, and experimentation is costly when unconventional wells cost more than $4 million to $6 million. See Fisher, K., 2012, "Green frac fluid chemistry optimizes well productivity, environmental performance," *American Oil and Gas Reporter*, http://www.aogr.com, March 2012.

[57] A comparison of regulations by state as of July 2012 can be found in Resources for the Future, 2012, *Managing the Risks of Shale Gas Development: Identifying a pathway toward responsible development: A review of shale gas regulations by state*.

[58] For example, Halliburton has developed "Clean Stim" as a fluid using only "food industry" ingredients. Information is available at http://www.halliburton.com/en-US/ps/stimulation/fracturing/cleanstim-hydraulic-fracturing-fluid-system.page.

[59] FracFocus is an online repository (available at http://www.fracfocus.com) for disclosure of chemical constituents in hydraulic fracturing fluids, and is operated by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission.

[60] A list of all chemicals used in hydraulic fracturing from 2005 through 2011 can be found in Appendix A of the EPA "Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report," December 2012, available at http://www.epa.gov/hfstudy. EPA has not yet made a determination of toxicity for these additives.

Federal law does not require disclosure of the chemical composition of hydraulic fracturing fluids. The U.S. Department of the Interior has proposed rules requiring disclosure for wells drilled on public lands.[61] All states with chemical disclosure requirements provide various exemptions for proprietary chemicals that are considered "trade secrets" specific to a particular company.[62]

A few examples of additives, which have specific purposes, are

- biocides to prevent bacterial growth that could inhibit well performance and possibly create potentially toxic gases such as hydrogen sulfide;
- friction reducers to minimize the power needed to pump hydraulic fracturing fluids downhole to create the level of pressures required for effective fracturing of reservoir rock; and
- scale inhibitors to prevent minerals from precipitating at critical places in a well that might significantly reduce production efficiency.

Some traditional additives are toxic, and can reappear in flowback water. A number of large industry players have committed to eliminating some additives by conducting tests of their effectiveness in different formations and/or to providing suitable nontoxic substitutes that are effective during reservoir stimulation.[63] Some of these alternative additives were originally developed for use in the food industry.[64] To be successful in the marketplace, the performance of such "green" additives must equal or exceed the performance of traditional fracture stimulation fluids.

Alternative Hydraulic Fracturing Fluids and Methods

A potential water-saving process with other potential advantages is the use of carbon dioxide (CO_2) or other water-free agents such as nitrogen (N_2), methane (CH_4), ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}), as fracturing fluids. Nitrogen is a common inert, nonsorbing, and compressible fracturing fluid (usually used as a foam); carbon dioxide is a corrosive, highly sorbing,[65] compressible fluid; and methane, ethane, and propane are noncorrosive, highly sorbing, compressible fluids. This category or grouping of gases is often referred to as liquefied petroleum gas (LPG). An additional advantage to their use is that these alternative fluids may limit formation damage that characterizes the application of water to certain shale mineralogies, particularly those rich in certain clay minerals that swell upon contact with water.

A fundamental motivation for the use of carbon dioxide is the possibility for superior performance in generating the connected pores that allow a more efficient extraction of natural

[61] As of the end of 2013, the most recent set of draft rules is available at http://www.blm.gov/pgdata/etc/medialib/blm/wo/Communications_Directorate/public_affairs/hydraulicfracturing.Par.91723.File.tmp/HydFrac_SupProposal.pdf.

[62] Guidance from the American Petroleum Institute (API) suggests that operators should disclose information on chemical additives and their composition when requested, and that "best practice is to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness."

[63] See Fisher, K., 2012, "Green frac fluid chemistry optimizes well productivity, environmental performance," *American Oil and Gas Reporter*, http://www.aogr.com, March 2012.

[64] Joint Institute for Strategic Energy Analysis, 2012, *Natural Gas and the Transformation of the U.S. Electricity Sector*, National Renewable Energy Laboratory Report NREL/TP-6A50-55538, available at http://www.nrel.gov/docs/fy13osti/55538.pdf.

[65] Sorbtion is a process by which one substance becomes attached to another and includes adsorption (adherence onto the surface of another substance) and absorption (incorporation into a substance of a different state (e.g., a liquid being absorbed by a solid).

gas, essentially increasing the permeability so that natural gas can flow more easily from the pores in the rock to the production well. In addition, as illustrated in **Figure 11**, the use of carbon dioxide may enhance production of methane because carbon dioxide can replace or "kick off" methane sorbed to the solid organic material in the shale. This property could also allow for a modest sequestration of carbon dioxide in a shale reservoir.

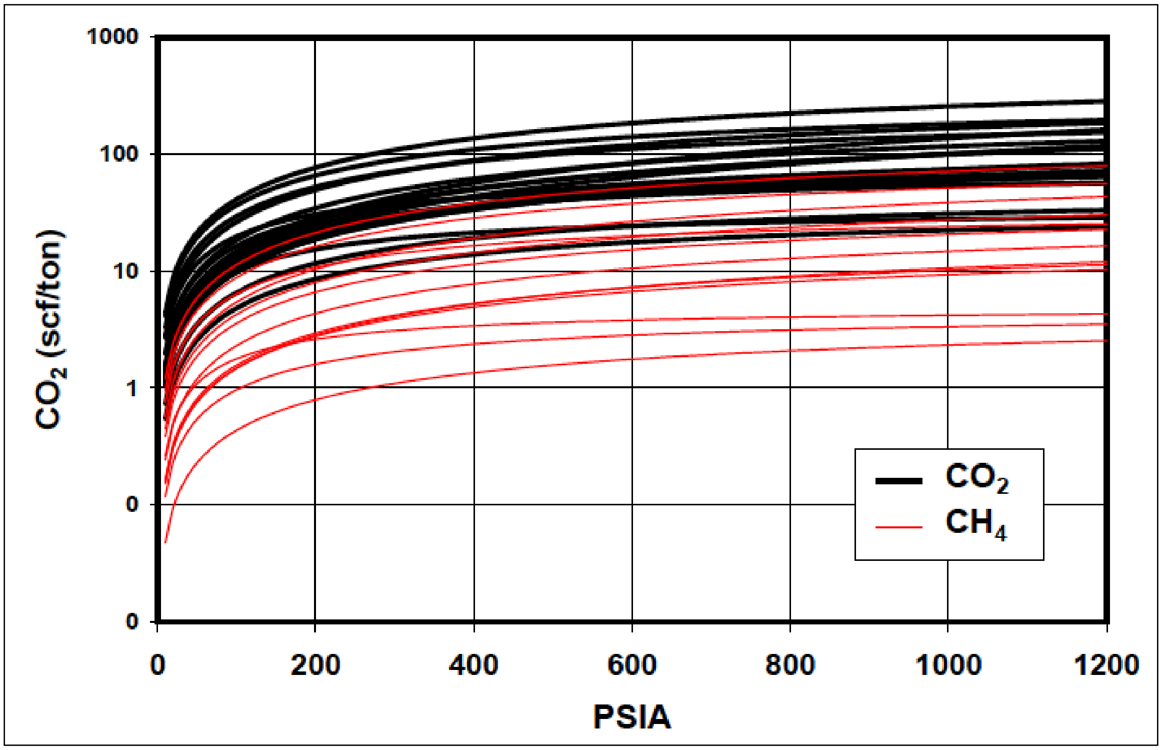
The LPG combination is sometimes referred to as "gas frac" methodology. It has been applied successfully in tight-gas sand reservoir stimulations, primarily in Canada.[66] In addition to reducing water use, flowback, and formation damage, there are additional benefits to each of the alternative fluids, and some disadvantages. One advantage is that all of the gas flowback after stimulation can be recaptured at the wellhead and reused. Also, for some shale formations, the use of hydrocarbon gases prevents "water blocks" (in which water clogs pores in low-permeability shale formations) that might occur with slickwater fracking. Carbon dioxide provides the same benefit.

One disadvantage of using carbon dioxide and other gases instead of water is the relatively high commodity costs, as well as transportation costs for linking sources of carbon dioxide and other alternatives to a well site. Their use also may raise a number of other issues related to safety and possible environmental impacts. If LPGs are used instead of water, first responders or emergency personnel may be exposed to additional risks in the case of well fires, blowouts, or other incidents. In addition, using LPG fluids introduces the possibility of fugitive hydrocarbon emissions during or after the completion of a gas frac, which could pose health and environmental concerns for groundwater, surface water, and air quality.

[66] Tight sand gas accumulations occur where gas migrates from a source rock into a sandstone formation with relatively low permeability compared to other "conventional" sandstone formation reservoirs. The relatively low permeability of the tight sandstone limits the ability of the gas to migrate further upward without an enhanced recovery technique such as fracturing.

Figure 11. Carbon Dioxide (CO_2) and Methane (CH_4) Adsorbtion onto Organic-Rich Devonian Black Shale From Kentucky and Ohio

(as a function of gas pressure)



Source: Nuttall, B.C., Eble, C.F., Drahovzal, J.A., and Bustin, R.M., 2005, *Analysis of black shales in Kentucky for potential carbon dioxide sequestration and enhanced natural gas production*, Final Report to U.S. Department of Energy, DE-FC26-02NT41442.

Note: The figure provides a summary of adsorption isotherms (where psia measures gas pressure) and indicates a higher sorption capacity (Y axis) for carbon dioxide compared to methane, which means that carbon dioxide would be preferentially adsorbed to black shale and methane would be released.

Multilateral Wells

This technique, using lateral horizontal wells that branch off the main vertical wellbore, so that multiple shale horizons can be tapped from a single surface well pad, often leads to a reduced surface footprint and improved economics. It does not necessarily lead to savings in water volume used during fracturing. Other advantages, however, include less rig time, truck traffic, and fewer fluid lines.[67]

Closed System Completions

Closed-loop systems (referred to as reduced emission or "green" completions) for handling flowback and reducing gas leakage and flaring have been used in some U.S. gas shale plays. Closed-loop systems help to minimize the exposure of produced fluids to the environment (air or water), with the intent of reducing the risk of water contamination and air pollution.

[67] Joshi, S.D., 2007, "Reservoir aspects of horizontal and multilateral wells," 265 p., SPE Ann. Tech. convention, 2007; Greenberg, J., 2012, "Today's technologies support operator goals," 2012 *North American Unconventional Yearbook: Technology*, http://www.hartenergy.com.

Typically, in regions of rapid hydrocarbon exploration, the rate of well drilling exceeds the ability of industry to bring gathering lines (small-diameter pipelines to provide takeaway capacity for natural gas) to individual well pads. When completing wells that are fractured without gathering lines in place, there is a period of three to 10 days (up to 60 days) during which produced fluids from the well must be captured, stored, and ultimately disposed of, or treated or reused. During this period, natural gas also flows from the well, but cannot be effectively captured without storage and transport facilities in place. It is a common practice to "flare" the gas—burning the produced gas and converting it to carbon dioxide—rather than venting natural gas directly (carbon dioxide is a less powerful, albeit more persistent, greenhouse gas than methane). One company, Devon Energy, has dedicated itself to using such closed-loop completions in the Texas Barnett Shale. The Barnett Shale play, however, has the advantage of an existing oil and gas production infrastructure in a well-established producing area.[68] In newer shale plays such as the Marcellus Shale and the Bakken Shale, wells may be drilled prior to the development of the infrastructure needed to transport gas to market (see **Figure 12**). In such instances the natural gas generated during well completion is typically flared. For example, from 2008-2012 gas production in North Dakota from the Bakken Shale oil play accounted for 0.5% of total natural gas extracted in the United States; however, the amount flared in North Dakota was approximately 22% of all natural gas that was either flared or vented in the United States.[69]

The EPA has mandated that, with some exceptions, onshore natural gas wells must adhere to "green completion" guidelines by 2015.[70] This means that completions must be made within a closed system that allows separation of the water and gas phases, thereby significantly reducing greenhouse gas emissions, as well as those of volatile organic compounds (VOCs).[71] (The EPA rule does not apply to wells drilled primarily for production of crude oil, such as wells in the Bakken Formation.)

[68] Devon's green-completion process, which involves capturing methane rather than flaring, is described at http://www.dvn.com/CorpResp/initiatives/Pages/GreenCompletions.aspx.

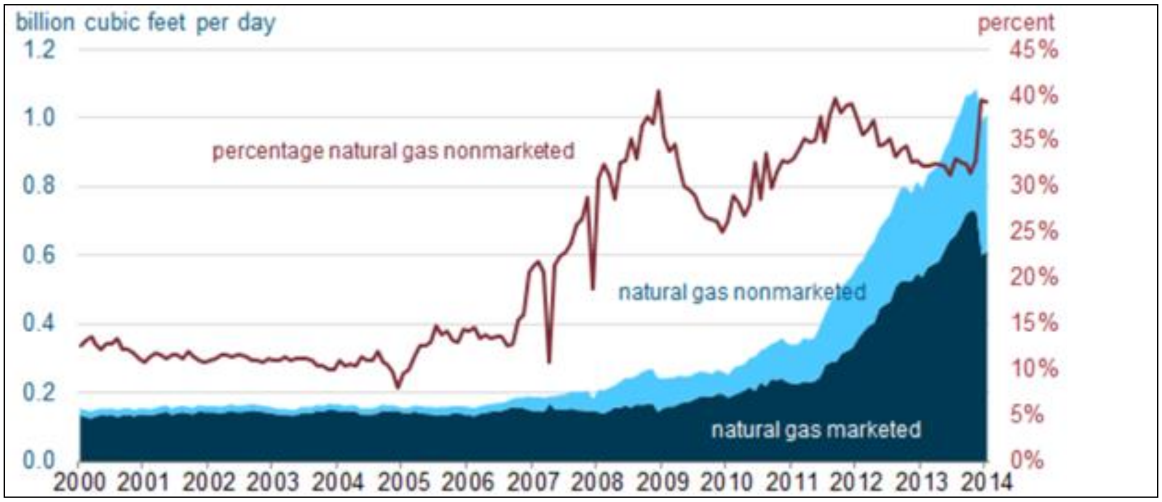
[69] U.S. Energy Information Administration, *Today in Energy*, republished March 21, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15511&src.

[70] U.S. EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012.

[71] For more analysis, see CRS Report R42833, *Air Quality Issues in Natural Gas Systems*, by Richard K. Lattanzio.

Figure 12. North Dakota Natural Gas Production

(marketed and nonmarketed gas 2000-2013)



Source: U.S. Energy Information Agency, *Nonmarketed Natural Gas in North Dakota Still Rising Due to Higher Total Production*, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=4030, and http://www.eia.gov/todayinenergy/detail.cfm?id=15511&src.

Notes: Natural gas production in North Dakota's portion of the Bakken Formation has grown with increased oil production. In 2013, natural gas production continued to outpace pipeline capacity: nonmarketed natural gas increased to an average of 0.13 billion cubic feet per day (Bcf/d) through the end of 2013, compared to 0.16 Bcf/d levels in 2011. However, nonmarketed gas, as a percentage of total production, decreased from 37% in 2011 to 33% in 2013, as several infrastructure projects came online. Most nonmarketed gas is flared.

Produced Fluids Management and Treatment Technologies

A variety of produced fluids water management strategies and treatment technologies are being used in shale energy development to reduce the need for use of freshwater and disposal of produced fluids. Treatment costs can vary widely by method, as outlined in **Table 3**, from a few cents to tens of dollars per thousand gallons treated. Advances in new water treatment technologies are being developed domestically in response to evolving demands of the shale energy industry, and also are being imported from an array of international and foreign companies with specialized expertise.

Produced Fluid Treatment and Recycling Technologies

The recycling of produced fluids is increasing in shale plays across the United States, most prominently in the Marcellus Shale play. The primary driver for water treatment prior to reuse of produced fluids for hydraulic fracturing operations is to minimize the possibility of shale gas reservoir damage, such as chemical or physical plugging, that might be induced by constituents present in produced fluids. A damaged reservoir could reduce oil or gas production. In particular, high chloride levels can interfere with friction reducers and reduce fracturing efficiency, while divalent cations such as barium, strontium, calcium, and iron can precipitate with sulfates or carbonates, thus forming scale within fractures and contributing to fracture plugging.

As shale energy development and produced fluids reuse for fracturing operations have increased, operators have increased their use of a suite of treatment technologies to minimize the potential for shale reservoir damage. The increased reuse is due in part to improved fracturing mixtures that are brine-tolerant, thus allowing the use of produced fluids for hydraulic fracturing. Based on review and analysis of Pennsylvania Department of Environmental Protection (PA DEP) records for unconventional well development for 2012, 23.2 million barrels of produced fluids were reused out of a total of 26.8 million barrels generated, a reuse rate of approximately 87%. By comparison, the reuse rate in Pennsylvania in 2011 was 72% (12.1 million barrels reused versus a total of 16.9 million barrels of produced fluids). The percentage of reuse varies in other states. In Colorado, some reports indicate that most produced water is reused, and some operators claim that all produced fluids were reused in hydraulic fracturing operations in the Piceance Basin.[72] The percentage of reuse varies by shale play in Texas, but appears to be much lower than in Colorado, from 0% reuse in the Eagle Ford Shale play to 5% in the Barnett Shale play, based on information from 2011.[73]

There are two major recycling approaches: use of field management technologies deployed at or near drilling sites, and use of centralized treatment facilities, as described below.

Field Treatment and Recycling

A variety of approaches have been developed to reuse produced fluids in the field, with the primary advantages of minimizing the transport of wastewater, which reduces trucking costs, fuel use, carbon emissions, the potential for trucking accidents, and road damage. The major requirements by operators for the use of these technologies are that they effectively remove contaminants, have high recovery rates, are low maintenance, have a small footprint, and are operationally robust enough to handle a range of fluid qualities. A review of the options for field treatment and reuse, along with advantages and disadvantages, is summarized below.

Direct Reuse with Blending

Recovery of produced fluids and direct reuse of them for subsequent hydraulic fracturing typically involves blending of the return fluids with fresh makeup water in order to have the necessary volume of water for hydraulic fracturing. This approach may involve allowing coarser sediments to settle out in tanks; however, suspended particles may remain.

The primary advantage of this technique is the relatively low costs involved with storage of fluids in approved containment (e.g., double-lined centralized impoundments or steel tanks) and the operational costs associated with blending in freshwater. However, the quality of such blended water may be suboptimal. A disadvantage with direct reuse is increased risk of reservoir damage associated with either suspended sediments or multivalent scaling agents such as calcium, barium, strontium, iron, sulfate, or carbonate.

[72] Colorado Oil and Gas Association, 2011. *Produced Water Fast Facts*; U.S. EPA, 2011, *Proceedings of the Technical Workshops for the Hydraulic Fracturing Study: Water Resources Management*.

[73] Nicot, J.P., Reedy, R.C., Costley, R.A., and Huang, Y., 2012, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report*, prepared for Texas Oil & Gas Association, Austin, TX.

Filtration

Filtration technologies range from the use of bag filters designed to reduce suspended sediment concentrations to more sophisticated micro- or nanofiltration technologies with the ability to also reduce multivalent ion concentrations (scalants). Based on a survey of Marcellus Shale play operators, the industry criteria for produced fluids reuse are shown in **Table 4**, including suspended particle size of <20 micron,[74] which can be achieved by all advanced filtration technologies. Filter socks would not reduce scaling agent concentrations, but micro- or nano-filtration would be effective in ion removal (although this would require power and additional operational oversight, thus increasing the cost).

Table 4. Suggested Maximum Concentration of Chemical Constituents in Produced Fluids for Reuse

Chemical Parameter	Maximum Value (mg/L)
TDS	50,000
Hardness	26,000
HCO_3	300
SO_4	50
Cl	45,000
Ca	36,000
Na	8,000
Mg	1,200
K	1,000
Fe	10
Ba	10
Sr	10
Mn	10

Source: U.S. Department of Energy National Energy Technology Laboratory, RPSEA Project 07122-12, 2009, *An Integrated Framework for Treatment and Management of Produced Water.*

Note: mg/L is milligrams per liter.

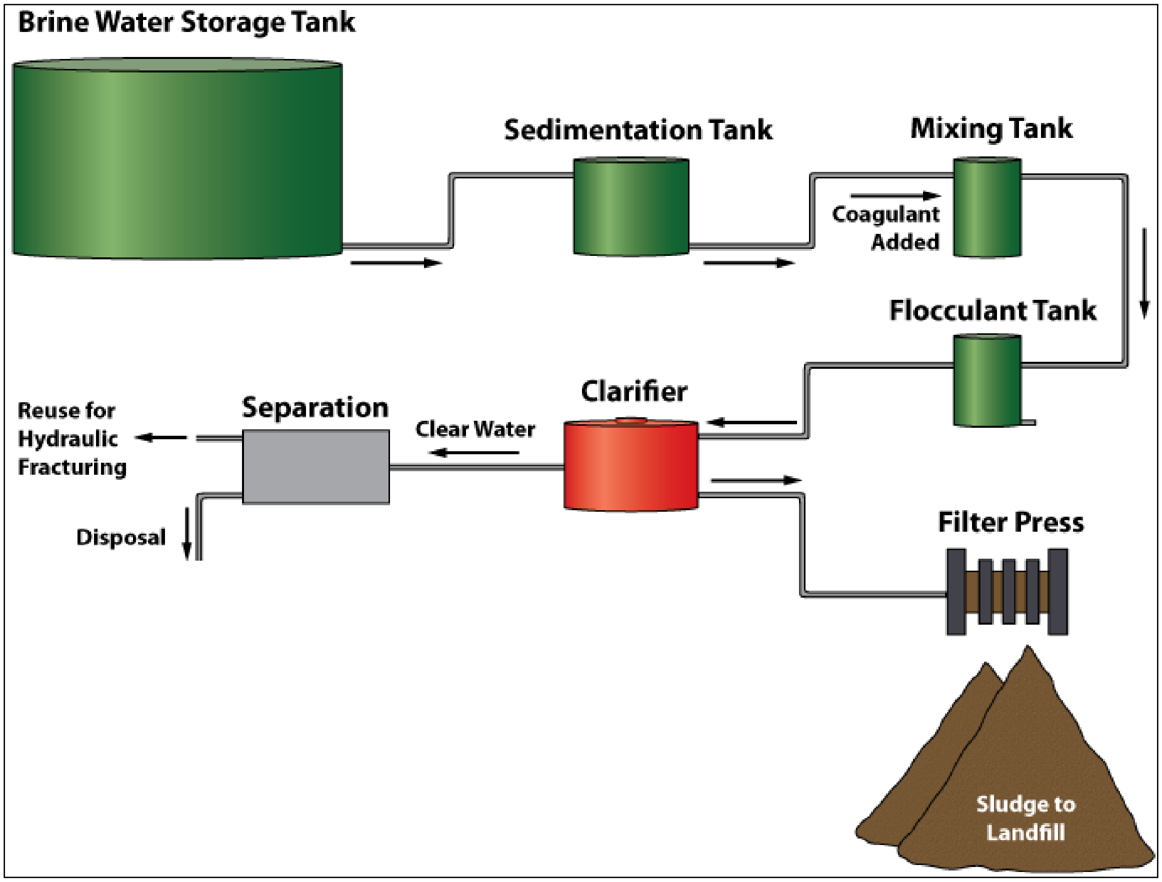
The advantage of filtration technologies is that they require low to moderate maintenance while achieving moderate to high scalant removal efficiency. These technologies also achieve high recovery (>90%); therefore, they have high reuse potential, thus minimizing the need to dispose of residual wastes. Waste consisting of either spent bag filters or reject waters requires appropriate disposal, and adds to waste management costs.

[74] U.S. Department of Energy National Energy Technology Laboratory Project DE-FE0001466, 2012.

Chemical Precipitation

This class of treatment technologies uses a relatively conventional chemical addition process to remove scalants from the wastewater stream by increasing the pH and adding a coagulant that causes positively charged ions (cations) to precipitate out as sludge. The water is then run through a clarifier, and the sludge is separated, collected, dewatered, and ultimately disposed of in a permitted landfill. This process is highly effective at removing scaling agents at a moderate cost, though it does require greater maintenance to adjust chemistry with varying influent water quality. **Figure 13** shows the typical treatment scheme for use of this technology.

Figure 13. Typical Chemical Precipitation Treatment Scheme for Produced Waters Reuse



Source: Earth and Mineral Sciences Energy Institute, Pennsylvania State University.

Electrocoagulation

Electrocoagulation is the process of destabilizing suspended, emulsified, or dissolved contaminants in an aqueous medium by introducing an electric current into the medium through an electrolytic cell with one anode and one cathode. Once charged, the particles coagulate to form a mass, and can be combined with electroflotation to effectively remove contaminants from water with the advantages of reduced sludge production, no requirement for chemical use, and ease of operation, with recovery rates of approximately 95%.[75]

Desalination

Mobile desalination technologies have been developed to remove a high percentage of total dissolved solids, including both scaling agents and salts. The most widely used technologies include pressure-driven (i.e., reverse osmosis) and thermal-driven (direct heat), or a combination of pressure- and thermal-driven (mechanical vapor recompression, or MVR) technologies. The advantage of desalination is that a very clean effluent is produced and can easily be recycled, or, with proper permitting, even potentially discharged to a stream or river. The primary disadvantage is that the electricity required results in high associated energy costs.

Reverse osmosis can be used to treat only fluids having a total dissolved solids (TDS) of approximately less than 45,000 milligrams per liter (mg/L), and therefore can be used only in shale plays with lower-TDS produced fluids. It may be most effective in the Fayetteville Shale or Woodford Shale, but not the Marcellus Shale.[76] Pretreatment is generally required (typically chemical precipitation) to avoid membrane fouling. In addition to producing treated water, reverse osmosis also produces an even more saline waste concentrate which requires handling and disposal.

In contrast, thermal technologies can handle TDS loads of 100,000 mg/L (or higher), and therefore can be broadly applied in most shale plays. Thermal processes require pretreatment to soften water prior to either application of direct heat to boil the water, or use of MVR, where the water is both heated and compressed to add the energy required to boil water. In MVR the heated water is fed through preheat exchangers to absorb heat from the distillate and concentrate products, and passes into a recirculation loop where concentrate circulates through an evaporator exchanger and a vapor/ liquid separator.[77] Fluid recovery using direct-heat thermal technology results in fluid recovery efficiency of upwards of 56%,[78] whereas use of MVR is more energy-efficient and can achieve fluid recovery efficiency of upwards of 90% efficiency for reuse.[79] The higher efficiency means less concentrate to dispose of or treat further.

Centralized Treatment Facilities

The use of centralized treatment facilities for produced fluids management involves the use of a similar suite of technologies as summarized above. Whether centralized or on-site treatment is a preferred option depends on the trade-off between the cost of transporting produced fluids to and from the treatment site and the economies of scale possible with larger treatment facilities. Depending on the location of the facility in relation to drilling locations, transport distances can be great; therefore, trucking costs can be significant.

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[75] Emamjomeh, M., Sivakumar, M., 2009, "Review of pollutants removed by electrocoagulation and electrocoagulation/flotation processes," *Journal of Environmental Management* 90, pp. 1663-1679.

[76] Acharya, H.A., Henderson, C., Matis, H., Kommepalli, H., Moore, B., Wang, H., 2011, *Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use*, Department of Energy: DE-FE0000784 Final Report.

[77] U.S. Department of Energy National Energy Technology Laboratory, RPSEA Project 07122-12, 2009, *An Integrated Framework for Treatment and Management of Produced Water*.

[78] U.S. Department of Energy National Energy Technology Laboratory, RPSEA Project 08122-36, 2012, *Produced Water Pretreatment for Water Recovery and Salt Production*.

[79] U.S. Department of Energy National Energy Technology Laboratory, RPSEA Project 07122-12, 2009, *An Integrated Framework for Treatment and Management of Produced Water*.

As indicated by PA DEP records, during 2012 there were 17 treatment facilities in Pennsylvania that actively treated Marcellus Shale wastewater for reuse for hydraulic fracturing. All of the facilities relied on chemical precipitation as the primary treatment, with two other facilities having advanced desalination capacity using thermal technologies. The total capacity of the facilities was approximately 4 million gallons per day. In contrast, based on analysis of Marcellus Shale wastewater during 2012, on average only about 15% of the waste (462,000 gallons per day) went to centralized treatment facilities for recycling purposes. This suggests that approximately 11% of the existing recycling treatment plant capacity was utilized. The remaining 85% (2.6 million gallons per day) of the recycled produced fluids was managed in the field.

While the most recent PA DEP waste production data suggest an estimated 87% of produced fluids were being recycled for hydraulic fracturing operations, approximately 13% of the fluids needed to be disposed of according to applicable regulations. The primary means of disposal of the remainder of the produced fluids is through the use of UIC Class II disposal wells, as discussed earlier in this report.

Status of Emerging Produced Fluids Technologies or Practices

This section evaluates the status of emerging technologies and their potential future roles, based on advantages and limitations of each. Most are chemical techniques that require concentration gradients across a semipermeable membrane, and are presently in small-scale use or experimental research and development phases. An overview of the classes of technologies being researched or under development and a summary of viable advantages and disadvantages of each approach are also presented.

Electrochemical Processes

Electrochemical processes separate dissolved ions from water through ion-permeable membranes or conductive adsorbers through the use of an electrical potential gradient. A summary description of each technology is provided below.[80]

- **Electrodialysis (ED).** An ED unit consists of a series of anion exchange membranes (AEM) and cation exchange membranes (CEM) arranged in an alternating mode between anode and cathode. Positively charged cations migrate toward the cathode, pass the CEM, and are then rejected by the AEM. The opposite occurs when negatively charged anions migrate to the anode. This results in an alternating increasing ion concentration in one compartment (concentrate) and decreasing concentration in the other (diluate).
- **Electrodialysis reversal (EDR).** The EDR process is similar to the ED process, except that it also uses periodic reversal of polarity to minimize membrane scaling and fouling, thus allowing higher water recoveries.
- **Electrodeionization (EDI).** This is an existing commercial desalination technology that combines ED and conventional ion exchange technologies. A mixed-bed ion exchange resin or fiber is placed into the diluate cell of a conventional electrodialysis cell unit to increase the conductivity in the substantially nonconductive water. The process can be performed continuously

[80] Much of the technical description in this section is based upon Drewes, J., T.Y. Cath, P. Xu, J. Graydon, J. Veil, S. Snyder, 2008, *An Integrated Framework for Treatment and Management of Produced Water*, RPSEA Forum, Golden, CO, available at http://www.rpsea.org/attachments/wysiwyg/681/cath1.pdf.

without chemical regeneration of the ion exchange resin, and can reduce the energy consumption when treating low-salt solutions.

- **Capacitive deionization (CDI).** CDI is an emerging desalination technology where ions are adsorbed onto the surface of porous carbon electrodes (e.g., activated carbon) by applying a low-voltage electric field, thus producing deionized water.

Electrochemical charge-driven separation processes are typically used in desalination of brackish, not highly saline water, significantly reducing the applicability of these technologies to most shale plays. The cost and energy consumption of these processes increase substantially with increasing salinity or TDS concentration. These processes are less prone to fouling as compared to reverse osmosis and nano-filtration membranes. However, low-solubility inorganic salts (e.g., calcium sulfate, calcium carbonate) and multivalent ions (e.g., iron and manganese) can scale the membranes; thus requiring pretreatment.

Ceramic Microfiltration/Ultrafiltration Membrane

Ceramic ultrafiltration and microfiltration membranes consist of a tubular configuration where the feedwater flows inside the membrane channels and permeates through the media to the outside to remove particulates, organic matter, oil and grease, and metal oxides. Due to their extreme stability in harsh environments, ceramic membrane has been reported to be a promising way for produced water purification.[81] Pretreatment using chemical precipitation or a strainer or cartridge filter is necessary as pretreatment for ceramic membranes. Energy requirements for ceramic membranes are lower than those required for polymeric membranes, but ceramic membranes have a higher capital cost than polymeric membranes.[82] The application of ceramic membranes for produced water treatment may increase as more research and pilot studies are conducted.

Membrane Distillation

Membrane distillation (MD) is a thermally driven separation (microfiltration) process, in which only vapor molecules are able to pass through a porous hydrophobic membrane driven by the vapor pressure difference existing between the porous hydrophobic membrane surfaces.[83] MD is the only membrane process that can maintain process performance (i.e., water flux and solute rejection) almost independently of feed solution TDS concentration.[84] MD is capable of producing ultra-pure water at a lower cost compared to conventional distillation processes, and is flexible for most variations in produced feedwater quality and quantity.[85]

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[81] Zhang, H., Zhong, Z., Xing, W., 2013, "Application of ceramic membranes in the treatment of oilfield-produced water: Effects of polyacrylamide and inorganic salts," *Desalination* 309, pp. 84-90.

[82] Drewes, J., T.Y. Cath, P. Xu, J. Graydon, J. Veil, S. Snyder, 2008, *An Integrated Framework for Treatment and Management of Produced Water*, RPSEA Forum, Golden CO, available at http://www.rpsea.org/attachments/wysiwyg/681/cath1.pdf.

[83] Alkhudhiri, A., Darwish, N., Hilal, N., 2013, "Produced water treatment: Application of Air Gap Membrane Distillation," *Desalination* 309, pp. 46-51.

[84] Drewes, J., T.Y. Cath, P. Xu, J. Graydon, J. Veil, S. Snyder, 2008, *An Integrated Framework for Treatment and Management of Produced Water*, RPSEA Forum, Golden CO, available at http://www.rpsea.org/attachments/wysiwyg/681/cath1.pdf.

[85] Alkhudhiri, A., Darwish, N., Hilal, N., 2013, "Produced water treatment: Application of Air Gap Membrane Distillation," *Desalination* 309, pp. 46-51.

Forward Osmosis

Forward osmosis (FO) is a developing membrane process technology that treats wastewater and requires no energy to push the flow through the membrane system, thereby lowering operational costs. A draw solution is employed across the alternate side of the membrane to generate a pressure gradient with a higher pressure on the side containing the waste stream.[86] The membranes used for this process are dense, nonporous barriers similar to reverse osmosis (RO) and nano-filtration (NF) membranes, but are composed of a hydrophilic, cellulose acetate active layer.[87] Typically, the FO draw solution is composed of sodium chloride, but other draw solutions (e.g., ammonium hydrocarbonate, sucrose, and magnesium chloride) have been proposed. During FO, the feed solution is concentrated while the draw solution becomes diluted, and thus must be continuously reconcentrated for sustainable system operation. A challenge is the amount of energy needed to regenerate the draw solution; if waste heat is available the energy inputs to the process can be reduced. One option is the use of RO for reconcentrating the draw solution and producing fresh product water for beneficial use or discharge. FO membranes may be capable of operating with a wide variety of produced fluids with TDS ranging from 500 milligrams per liter to more than 100,000 milligrams per liter, and are capable of rejecting all particulate matter and almost all dissolved constituents (greater than 95% rejection of TDS).[88] These attributes also allow FO to achieve very high theoretical recoveries while minimizing energy and chemical demands; in practice, the recovery rate may be closer to 70%.[89]

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[86] Olawoyin, R., Madu, C., Enab, K., 2012, "Optimal Well Design for Enhanced Stimulation Fluids Recovery and Flow-back Treatment in the Marcellus Shale Gas Development using Integrated Technologies," *Hydrology Current Research* 3:141. doi:10.4172/2157-7587.1000141.

[87] Drewes, J., T.Y. Cath, P. Xu, J. Graydon, J. Veil, S. Snyder, 2008, "An Integrated Framework for Treatment and Management of Produced Water," RPSEA Forum, Golden CO, available at http://www.rpsea.org/attachments/wysiwyg/681/cath1.pdf.

[88] Olawoyin, R., Madu, C., Enab, K., 2012, "Optimal Well Design for Enhanced Stimulation Fluids Recovery and Flow-back Treatment in the Marcellus Shale Gas Development using Integrated Technologies," *Hydrology Current Research* 3:141. doi:10.4172/2157-7587.1000141. Bryan D. Coday et al., "The sweet spot of forward osmosis: Treatment of produced water, drilling wastewater, and other complex and difficult liquid streams," *Desalination*, no. 333 (2013), pp. 23-35.

[89] Bryan D. Coday et al., "The sweet spot of forward osmosis: Treatment of produced water, drilling wastewater, and other complex and difficult liquid streams," *Desalination*, no. 333 (2013), pp. 23-35.

Conclusions and Future Considerations

Common approaches for shale energy water management have included trucking of water from the source to the site; storing water in lined, earthen impoundments; and recycling of some portion of produced fluids for reuse in hydraulic fracturing, either at a fixed site or in the field, with the remainder of the fluids disposed of through injection wells or by some other treatment and disposal method. This type of water management approach has limitations, including the production of wastes requiring disposal and the use of significant volumes of fuel for water and waste transport, typically at significant cost. In order to make the process more cost-effective with less environmental impact, new approaches are being sought—for example, the use of lesser-quality sources of water, piping of water where possible, modular water storage, and recycling of produced fluids. Chemical precipitation for scalant removal and mechanical vapor recompression for desalination appear to be the most widely used treatment approaches to date; however, emerging technologies including electrochemical treatment and forward osmosis appear promising. The use of UIC wells for disposal is also heavily relied upon, especially in Ohio and Texas, as a means to manage the portion of produced fluids not being recycled. Long-term viability and capacity of disposal wells are an area of active research to better understand the sustainability of this practice in various shale plays.

Technological progress or changes in water management practices could address some of the most visible impacts on water resources and reduce the risk of impacts on groundwater and surface water quantity and quality. Widespread adoption of fracturing practices that minimize the use of freshwater (groundwater, surface waters, or municipally sourced waters) may reduce pressures from the shale energy sector on scarce water supplies in more arid areas such as Texas and the Rocky Mountain states. In the Appalachian region, overall water supplies are not scarce, but the transportation of water from source to drilling site can involve high trucking costs. Wastewater management practices that minimize the handling of produced fluids and the use of multiple transportation and storage modalities could reduce the risk of impacts to water supplies. Adoption of drilling and completion practices that are less water-intensive and that minimize truck transportation could benefit water quality through reduced erosion along dirt and gravel access roads constructed alongside streams.

While reduction of stresses on water supplies and water quality would represent an environmentally positive step, it is important to realize that water management issues will not disappear entirely. Some freshwater will still be required for shale energy production—for example, in mixtures with flowback water for reuse in subsequent fracturing jobs. The shale energy sector is increasingly recognized as a water consumer (alongside agriculture, municipalities, industry, and electric utilities and other forms of energy production and conversion) in regional water planning and state and local allocation practices.

Adoption of emerging technologies and processes that minimize the water-use intensity of fracturing will have its own challenges, beyond the key issue of cost. For example, public perception is an important consideration in determining which technologies or processes are ultimately adopted and widely deployed. The use of carbon dioxide foam for fracturing, for example, replaces one intensive transportation need with another, since trucks will be required or a dedicated pipeline network will need to be built to deliver the fracking fluid commodity to the drilling location. Industry may be hesitant to adopt alternative technologies and processes if their use reduces energy production or increases costs from shale energy formations.

There continue to be fundamental uncertainties surrounding the acceptable or optimal chemical composition of fracking fluids that would meet emerging environmental concerns but still be effective fluids for hydraulic fracturing and shale oil and gas extraction. For example, even when treated to drinking water standards, acidic mine drainage may still have high sulfate concentrations that increase the potential for downhole precipitation with metals. Metal precipitation could cause plugging of fractures, thereby lowering rates of oil and gas production. The treatments required to lower sulfate concentrations in abandoned mine drainage, and even the extent to which different sulfate concentrations are associated with higher or lower oil and gas production rates, are uncertain and require more study.

The equipment, personnel, and other capital needed for the production of shale energy are highly mobile. Costs can increase or decrease as regional shale development patterns shift. Drilling rigs tend to be moved to those areas with the highest economic returns (for example, away from dry gas to oil producing areas). The mobility of drilling capital suggests that the demand for fracking fluids and wastewater management or treatment services will vary over the course of years or even months. Most treatment facilities, on the other hand, are built in fixed locations, and movement of treatment facilities imposes high costs. Mobile treatment facilities could be developed, but first-generation systems would likely have high costs due to first-of-a-kind engineering and an inability to take advantage of scale economies in water treatment. Variable demand for such facilities may imply that truck transportation, which can be costly and variable, will likely continue to be used until the costs of mobile treatment facilities decline.

Water management issues are relevant to the entire life cycle of shale energy development, because fluids will continue to be produced even after a well is drilled, fractured, and producing oil and/or natural gas. There also are multiple pathways for potential freshwater contamination. Therefore, research that views shale energy production in a life-cycle and materials-flow context may facilitate the identification of technologies and processes that can mitigate potential impacts along different stages of the shale energy development life cycle.

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